

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application)
of **DTE Electric Company** for)
Authority to Implement a Power)
Supply Cost Recovery Plan)
in its Rates Schedules for 2016)
Metered Jurisdictional Sales)
Of Electricity)

Case No. U-17920

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on October 28, 2016.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before November 18, 2016, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before December 9, 2016. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING
SYSTEM
For the Michigan Public Service Commission

Dennis W. Mack
Administrative Law Judge

October 28, 2016
Lansing, Michigan

STATE OF MICHIGAN
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FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On September 30, 2015, DTE Electric Company (DTE) filed an Application with the Michigan Public Service Commission (Commission) under §6j of 1982 PA 304 (Act 304). MCL 460.6j. Through that filing DTE seeks approval of Power Supply Cost Recovery (PSCR) Plan, along with other associated authorizations. The Plan is for the period of January 1, 2016 through December 31, 2016 (PSCR Year), and proposes a maximum PSCR factor of (0.20) mills per kWh for DTE's PSCR customers. In addition, DTE submitted a 5-year forecast for 2016-2020 of projected power supply requirements, sources of supply, and the cost of that supply.

Pursuant to due notice, a pre-hearing conference was conducted on November 25, 2015. DTE and Commission staff appeared at that proceeding, and intervention was granted to the Michigan Environmental Council and Sierra Club (MEC), Association of

Businesses Advocating Tariff Equity (ABATE), ANR Pipeline Company (ANR), Great Lakes Renewable Energy Association (GLREA), and the Attorney General. See 1 Tr 7-8, 40-42.¹

Consistent with the schedule established during the pre-hearing, the hearing was conducted on May 2, 3 & 4, 2016.² During the hearing, DTE entered the testimony of its employees: Matthew T. Paul, Executive Director – Generation Optimization & Corporate Fuel Supply; Ryan C. Pratt, Supervisor, Planning and Procurement, Fuel Supply Department; John O. Yurko, Senior Technical Specialist in Generation Optimization; James D. Wines, Lead Engineer – Nuclear Generation; Markus B. Leuker, Manager of Corporate Energy Forecasting; and Shawn D. Burgdorf, Supervisor of the Tactical Merchant Analytics in the Generation Optimization Department. From its affiliate, DTE Energy Corporate Services, LLC, DTE offered the testimony of Zachary T. Paquette, Senior Strategist – Federal Regulatory Affairs; Barry J. Marietta, Supervisor – Emissions Quality; and Kevin L. O'Neill, Principal Project Manager. DTE also offered the testimony of Robert G. Lawshe, Manager of Gas Supply and Planning for DTE Gas Company (DTE Gas); Maria F. Scheller, Vice President, Energy Advisory Services, with ICF International, and Michael D. Sloan, Principal, ICF International.³ Through these witnesses, DTE entered Exhibits A-1 through A-38.

The MEC entered the direct testimony of James F. Wilson, Principal, Wilson Energy

¹ DTE opposed ANR's intervention (1 Tr 17-29, 37-40), and reiterated that opposition in its Initial Brief (Dkt. #106, pg. 39).

² On May 26, 2016, DTE's Motion to Correct the Transcript from May 3 (Vol. 3 pg. 545, line 10) and May 4 (Vol. 4 pg. 800, line 17, and pg. 847, line 24) was granted under R 792.10415(4). Dkt. # 98.

³ Mr. Lawshe, only offered rebuttal testimony, while Mr. Paquette, Mr. Marietta, and Mr. O'Neill, only offered direct testimony. All of DTE's other witnesses provided direct and rebuttal testimony.

Economics, and Exhibits MEC-1 through MEC-17 and MEC-19 through MEC-48.⁴ The GLRA entered the testimony of Geoffrey C. Crandall, Principal and Vice President of MSB Energy Associates, Inc., and through this witness entered Exhibits GLREA-1 through GLREA-6. ANR offered the testimony of Lee Bennett, Manager, Pricing and Business Analysis, TransCanada, U.S Pipelines, and entered Exhibits ANR-1 through ANR-26. The Attorney General offered the testimony of Sebastian Coppola, an independent business consultant, and Exhibits AG-1 through AG-15. Neither ABATE nor Staff offered any witnesses or entered any exhibits.

Consistent with the schedule established during the pre-hearing, all of the parties, except ABATE, filed Initial Briefs. DTE, MEC, ANR, GLREA, and the Attorney General filed Reply Briefs.

II.

STATUTORY REQUIREMENTS

Act 304 provides for a PSCR clause that “permits the monthly adjustment of rates for power supply to allow the utility to recover the booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of fuel burned by the utility for electric generation and the booked costs of purchased and net interchanged power transactions by the utility, incurred under reasonable and prudent policies and practices.” MCL 460.6j(1)(a). Implementation of a PSCR clause requires the utility to annually file a

⁴ Exhibit MEC-40 and a portion of the cross-examination of Mr. Sloan (2 Tr 253-263) is maintained under a confidential record.

“plan describing the expected sources of electric power supply and changes in the cost of power supply anticipated over a future 12-month period specified by the commission and requesting for each of those 12 months a specific power supply cost recovery factor.”

MCL 460.6j(3). In addition, a PSCR plan must:

[D]escribe all major contracts and power supply arrangements entered into by the utility for providing power supply during the specified 12-month period. The description of the major contracts and arrangements shall include the price of fuel, the duration of the contract or arrangement, and an explanation or description of any other term or provision as required by the commission. The plan shall also include the utility's evaluation of the reasonableness and prudence of its decisions to provide power supply in the manner described in the plan, in light of its existing sources of electrical generation, and an explanation of the actions taken by the utility to minimize the cost of fuel to the utility.

MCL 460.6(j)(3).

Contemporaneous with the PSCR plan, a public utility must file with the Commission:

[A] 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs, in light of its existing sources of electrical generation and sources of electrical generation under construction. The forecast shall include a description of all relevant major contracts and power supply arrangements entered into or contemplated by the utility, and such other information as the commission may require.

MCL 460.6j(4).

In regards to the Plan, the Commission is to:

[C]onduct a proceeding, to be known as a power supply and cost review, for the purpose of evaluating the reasonableness and prudence of the power supply cost recovery plan filed by a utility pursuant to subsection (3), and establishing the power supply cost recovery factors to implement a power supply cost recovery clause incorporated in the electric rates or rate schedule of the utility.

MCL 460.6j(5).

For the Forecast, the Commission must:

[E]valuate the decisions underlying the 5-year forecast filed by a utility pursuant to subsection (4). The commission may also indicate any cost items in the 5-year forecast that, on the basis of present evidence, the commission would be unlikely to permit the utility to recover from its customers in rates, rate schedules, or power supply cost recovery factors established in the future.
MCL 460.6j(7).

DTE's PSCR clause was approved by the Commission in Case Nos. U-7510 and U-13808. Accordingly, this case entails a determination of the reasonableness and prudence of the decisions underlying the PSCR Plan and the proposed plan itself. MCL 460.6j(3), (5) and (6). In addition, the costs items in the 5-year forecast for the period of 2016-2020 will be reviewed to determine if, based on "present evidence", any of them are unlikely to be recovered in future proceedings. MCL 460.6j(7).

III.

DTE'S 2015 PSCR PLAN AND 5-YEAR FORECASTS

A. PSCR Plan

DTE's existing PSCR base is 31.26 mills per kWh, and the 2016 Plan projects costs below that level, resulting in a maximum PSCR Factor proposed in the Application of (0.20) mills per kWh. 4 TR 922-923; Exhibit A-3. DTE sets forth the following proposed findings of fact that it contends require approval of the 2016 Plan.

1. Load Forecast

For 2016, DTE forecasts annual electric sales of 47,370,000 kWh to Residential,

Commercial, Industrial, and Other rate classifications, which represents a slight increase from the 2015 total sales of 47,282,000 kWh, an amount derived from 7 months of actual, i.e. not temperature normalized, and 5 months of forecast. Exhibit A-6; 4 Tr 218. Electric Choice sales in 2016 are forecast at 5,049 GWh, with all going to Commercial and Industrial customers. Exhibit A-9. This represents an increase from Choice sales of 4,989 GWh in 2015. Id. The sales forecast is based on major economic parameters, such as Gross Domestic Product, Industrial Production, U.S. and Detroit Car and Truck Production, and Detroit Area employment and residential construction projections. 4 Tr 820-825; Exhibit A-10. For the Plan Year, DTE projects net system output of 50,816,000 kWh and peak demand of 11,410 MW. 4 Tr 818; Exhibit A-6.⁵ In light of the GLREA and Attorney General's challenge to certain components of the load forecast, DTE's proposed finding that it is reasonable and prudent is addressed below.

2. Purchased Power and Emission Compliance Costs

In 2016, DTE projects it will incur \$1,372,577,000 in PSCR costs to generate 43,492 GWh of electricity, which equates to \$31.56 MWh. Exhibit A-11. For this period, Mr. Burgdorf, who compiled the various components of the costs used to develop the proposed PSCR Factor, testified:

DTE expects that its generation (including fossil, nuclear, and DTE Electric Company-owned Renewable Energy Systems) as well as demand response resources (customers electing interruptible service under special contracts; R10, D8, R1.1, R1.2, the Interruptible Space-Conditioning Service Rate (D1.1), the Water Heating Service Rate (D5), and the Interruptible General Service Rate (D3.3)) will be credited with a total UCAP value of 11,034 MW

⁵ In May of 2014 DTE began using, and will use during the Plan Year, a new weather forecast for its day-ahead demand bids that has led to "greatly improved" variability of day-ahead accuracy. Id., 827-828.

for the 2016 Resource Adequacy Planning Year. In addition to its own resources, DTE has capacity rights from both PURPA/ P.A. 2 and 2008 P.A. 295 Renewable Energy Contracts (which are distinct from DTE Electric Company-owned Renewable Energy Systems) which are expected to have a total UCAP value of 205 MW. DTE is projecting 11,239 MW of Planning Resources for the 2016 Resource Adequacy Planning Year.⁶
4 Tr 858-859

Mr. Burgdorf noted the methodology used to formulate these costs is “largely the same as that used...” in DTE’s previous rate and PSCR Plan cases and “were modeled in PROMOD based on projections of wholesale energy market prices, projected load, and generating unit projections.” 4 Tr 864.

The second component of the proposed finding pertains to the PSCR costs resulting from 2016 emission allowances. DTE does not project incurring costs for NO_x because its emissions will be under its CSPAR allocation. 4 Tr 868-869; Exhibits A-15, A-16. Similarly, DTE projects its SO₂ emissions in 2016 will be below its allocations, negating the need to purchase allowances, but it will consume previously purchased allowances at a cost of \$84,407. 4 Tr 869-870; Exhibits A-17 and A-18. Should current allocations and previously purchased allowances not cover the actual emissions of NO_x and SO₂ in 2016, DTE will purchase additional allowances on the spot market, with the cost spread over a number of months to mitigate price volatility inherent in that market. 4 Tr 868, 871.

The Attorney General challenges certain aspects of these components of the Plan, *infra*. Therefore, the viability of DTE’s proposed finding that its 2016 generation, purchased power, and emission compliance expenses of \$1,372,577,000 are reasonable

⁶ Mr. Burgdorf also testified to 2016 renewable energy purchases under PURPA, 1989 P.A. 2, and 2008 P.A. 295, made through contracts and at transfer prices approved by the Commission. See 4 Tr 860-861. See also Exhibit A-14, pgs. 1 & 3. DTE-owned renewable generation and cost is depicted Exhibit A-14, pg. 2.

and prudent is addressed below.

3. Generation, Emission Quantities, and UREA Expenses

Mr. Yurko testified that the 2016 forecast of generation from Company-owned facilities is 12,369 MW, which is a 98 MW decrease from 2015. 4 Tr 718; Exhibit A-19. This decrease is attributed to the retirement of Trenton Channel Unit 7 on April 15, 2016, a corresponding decrease in generation from Unit 9, along with offsets from increases in generation from Ludington and solar sources. Id. Generation from Fermi 2 in 2016, 9,550 GWh, factors in “planned and unplanned losses in generation.” 2 Tr 785. Mr. Wines expanded on those factors:

The planned losses in generation include refueling outages as well as scheduled power reductions in support of required surveillances and necessary core management activities. Additionally, a reasonable amount of unplanned losses in generation are assumed. The combination of unplanned and planned losses in generation are discounted from the Fermi 2 expected demonstrated capability. It is these generation targets that are used to project the Fermi 2 fuel expenses tabulated in Exhibit A-1. The generation targets are used to determine the expected energy requirement for the fuel cycle.
4 Tr 785.

Mr. Yurko testified the 2016 generation projections were:

[D]eveloped utilizing PROMOD IV, which is a production cost simulation computer program. The program simulates the economic dispatch of the resources available to develop the generation projections, fuel consumption requirements and emissions (which impacts emissions allowance, urea, limestone, trona and activated carbon expense). The heat requirements associated with the fuel consumption are then utilized by Company Witness Mr. Pratt to develop unit fuel cost and fuel expense. The projections are for DTE’s generating resources and do not include Michigan Public Power Agency’s (MPPA) generation from the Belle River Power Plant. MPPA owns

approximately 18.6% of the Belle River Power Plant.
4 Tr 719.

This unit dispatch methodology, which factors MISO sales and purchases and emissions projections, has been used in DTE's rate and PSCR cases and from "2007 to 2014 has been 99.3% accurate over that time compared to actual generation." 4 Tr 720.

For 2016, DTE projects expenses of \$11,965,942 for urea, and \$2,517,567 for limestone. Exhibit A-21. Both compounds are used at the Monroe facility for emission control, and the expenses were calculated by the actual costs for a portion of 2015, plus an inflation factor and transportation cost for limestone. 4 Tr 723-724.

Because the Attorney General raised issues with certain aspects of this proposed finding, its viability is addressed below.

4. Transmission and MISO Expenses

For the Plan Year, DTE projects its expenses necessary to provide full service load requirements from the MISO Base Transmission and Ancillary Services Markets at \$316,000,000. Exhibit A-5. This amount represents Schedule 1, which is the charge for scheduling, system control and dispatch services from MISO, and Schedule 9, which is the ITC zonal rates for network integration transmission service. 4 Tr 882-883; Exhibit A-5. Other components of that expense is Schedule 2, reactive supply and voltage control services, Schedule 10, MISO cost recovery adder and FERC expense recovery, and Network Upgrade charges for new transmission projects to maintain baseline reliability. 4 Tr 883-889; Exhibit A-5. Mr. Paquette testified to DTE's role in MISO's Transmission Expansion Plan, along with DTE's involvement in federal regulatory proceedings regarding

transmission tariffs for MISO and ITC that may impact PSCR costs. 4 Tr 890-895.

As noted by DTE, none of the other Parties offered any evidence to refute the Total Base Transmission expenses testified to by Mr. Paquette, and contained in Exhibit A-5. Accordingly, DTE's request that these expenses be deemed reasonable and prudent, and recovered as PSCR costs in 2016, should be granted.

5. Fuel Supply

For the Plan Year, DTE projects its expenses for coal, oil, gas, coke oven gas, blast furnace gas, and petroleum coke, which are used in its fossil-fuel plants, and nuclear fuel, at \$878,185,000. Exhibit A-22. Mr. Pratt testified to the methodology used to arrive at this amount, particularly for coal that at \$727,357,000 for the Plan Year represents over 80% of the total 2016 fuel supply cost:

The 8 months actual, 4 months forecast (8&4 Outlook) for 2015 is the basis for the 2016-2020 forecasts. The 8&4 Outlook uses actual August 31, 2015, inventory quantities and costs, and forecasts deliveries and consumption for the remaining months of 2015. The forecasted December 31, 2015, inventory quantities and costs are inputs to the 2016-2020 forecasts.

The forecasted delivered costs for the last four months in 2015 and for 2016-2020 were determined using existing contract prices and transportation rates, forecasted forward market prices, and forecasted transportation rates. The forecasted forward market coal prices for 2016-2018 were based upon market information obtained from an over-the-counter coal broker. For 2019 and 2020, the forecasted coal cost was derived by applying an inflation index factor to the 2018 forward market coal prices. The forecasted transportation rates were computed by applying adjustments to current contract prices using forecasted rail cost adjustment factors based on historical data, along with fuel surcharges based on diesel oil forward pricing.

The monthly delivered coal cost for each plant was calculated by applying existing contract and forward coal prices and transportation rates to the

monthly delivery requirements for each plant. The coal delivery requirements are determined by subtracting actual August 31, 2015, coal inventory levels from the target coal inventory level and adding the coal consumption requirements provided to me by DTE Electric Fossil Generation's Strategic Planning 1 group as supported by Witness Yurko. This method is then used monthly for the remainder of the forecast period. The monthly delivered coal cost is added to the prior month's average coal inventory cost to derive an average coal cost available for consumption. Delivery requirements for oil and gas are determined in a similar manner. Fossil fuel expense was calculated by multiplying the average cost of fuel available for consumption by the monthly quantity of fuel consumed by plant and fuel type. 4 Tr 679-681.

DTE's coal supply will be obtained through long-term contracts, i.e. a duration of more than 1 year and detailed in Exhibit A-23, and spot purchases. 4 Tr 681. DTE expects that 91% of the coal it burns will be low sulfur western coal obtained from the Powder River Basin, with the remainder being mid sulfur eastern, high sulfur eastern, and low sulfur southern from Appalachia. 2 Tr 683. Mr. Pratt testified that DTE's effort to blend and burn supply from both regions, along with utilizing multiple transportation options, has allowed it "to negotiate some of the most competitive delivered fuel prices available." Id., 686. DTE does not anticipate any changes to its Reduced Emission Fuel Project, which reduces emission costs, first approved by the Commission in its June 28, 2013 Order in Case No. U-16892. See also January 19, 2016 Order, pg. 9, Case No. U-17680.

Other forms of fossil fuels includes No. 2 oil, which will be obtained under agreements that are for 3 years or less and based on a forward price index. 4 Tr 681. Natural gas will be acquired through a mix of long-term agreements, including the NEXUS Gas Transmission pipeline (NEXUS) commencing in November of 2017 and discussed below, agreements with LCDs, and spot market purchases. Id., 682. Coke oven gas and

blast furnace gas will continued to be supplied by DTE Energy Services, an affiliate, and is priced at 80% and 77% discount, respectively, of the actual unit cost of coal. Id. Finally, petroleum coke, which Mr. Pratt testified is the lowest cost fossil fuel, will be purchased under agreements of less than 1 year, and will be burned in place of higher-priced coal at DTE's Monroe Power Plant. Id., 682-683.

Nuclear fuel expense in 2016 is projected at \$57,283,000. Exhibits A-1 and A-22. Mr. Wines provided a detailed explanation of the nuclear fuel cycle process, and a background of DTE's contracts to obtain the fuels and refueling process at Fermi 2. 4 Tr 780-784. The nuclear fuel expense consists of the cost for ore, conversion, enrichment services, and fabrication, and are amortized as a PSCR expense over the life of the fuel. Id., 784. To arrive at that the 2016 costs, Mr. Wines testified:

Fermi 2's fuel cost projection is based on a reasonable set of assumptions on how Fermi 2 will operate in future years. Projected electrical generation is consistent with a 95% capacity factor when operating at power and with forty-day duration refuel outages occurring approximately every 18-months. 1 Additionally, nuclear fuel bundle loading quantities and nuclear fuel cycle component prices are fuel cost projection inputs as well. After inputs are processed, the inputs and results are checked by a second qualified individual. After additional reviews and completion of the comment resolution process, the fuel cost projection is published as an input to the DTE Electric PSCR Plan.

These are fuel expenses directly tied to projected generation from Fermi 2. Target generation, fuel expense, and total fuel expense through 2020 are tabulated in Exhibit A-1. The generation targets tabulated in column "(b)" account for planned and unplanned losses in generation.

The planned losses in generation include refueling outages as well as scheduled power reductions in support of required surveillances and necessary core management activities. Additionally, a reasonable amount of

unplanned losses in generation are assumed. The combination of unplanned and planned losses in generation are discounted from the Fermi 2 expected demonstrated capability. It is these generation targets that are used to project the Fermi 2 fuel expenses tabulated in Exhibit A-1. The generation targets are used to determine the expected energy requirement for the fuel cycle.

The purchase of Uranium, conversion services, enrichment services and fabrication for the fuel necessary to support the energy requirement is then amortized over a specified number of fuel cycles. The remaining portion of fuel expense includes regulatory costs such as disposal fees paid to the DOE pursuant to the Nuclear Waste Policy Act and Title 10, Part 961, Appendix G of the Code of Federal Regulations. Exhibit A-1 represents these expenses. Total fuel expenses, as depicted by column "(e)", is simply the sum of columns "(c)" and "(d)".

4 Tr 784-786.

Because the Attorney General raised one issue with DTE's projected fuel supply expense, the finding DTE seeks regarding its reasonableness and prudence is addressed below.

6. Mercury, Particulate Matter, and Acid Gas Emission Expenses

DTE utilizes a number of measures to bring emissions into compliance with the Mercury and Air Toxic Standards (MATS). Specifically, flue gas desulfurization (FSD) and selective catalytic reduction (SCR) at its Monroe facility, and as of April 2016, a combination of Dry Sorbent Injection (DSI) and an Activated Carbon Injection (ACI) system at its other coal-fired facilities. 4 Tr 901. Mr. Marietta testified the ACI system is used throughout the industry, is identified in a proposed federal rule as an effective measure of mercury control, and was reviewed by the Commission in DTE's previous PSCR Plan cases. Id., 904, 906-907. The chemicals used in these emission control processes,

BrPAC to reduce mercury and Trona to reduce acid gas, will cost \$19,982,683 in 2016, and are claimed as PSCR expenses as fuel costs and disposal cost of fuel. Id., 908; Exhibit A-2.

The 2016 projected expense is based on the process of the construction of the ACI and DCI systems as of September 2015. Mr. Marietta testified projection utilizes a different approach from previous cases as the MATS effective date approaches and construction continues:

Along with continuing to update this schedule, DTE Electric is committed to operating the systems prior to the MATS compliance date should the systems be available at that time. This means that several locations will have operational systems in place in late 2015 with others going into service early in 2016. Also, sorbent supply expense is becoming clearer as the operation dates draw near and DTE Electric has been able to better estimate the cost of the sorbents. The best current available cost information as of September 2015 is portrayed in Exhibit A-2.

A new development in this PSCR plan is that DTE is currently planning to use only BrPAC for mercury control in the ACI systems. This had always been the case for River Rouge and Trenton Channel Power Plants and is now the case for Belle River and St. Clair Power Plants. As engineering, construction and implementation of the ACI and DSI projects progressed, the gap in sorbent costs for standard PAC versus BrPAC became significantly smaller. For comparison, the current cost projection for standard PAC excluding transportation is \$0.60 per pound compared to \$0.75 per pound for BrPAC. As recently as two years ago, BrPAC was projected to be \$1.20 per pound, or double the cost of standard PAC. The difference in pricing between BrPAC and PAC has decreased by 75%. Due to the small gap in pricing, no redundant system was installed to allow for the use of two types of PAC simultaneously. PAC supply contracts will be fixed, long-term contracts to ensure future price certainty for the plan. In order to use two types of PAC in the ACI process, the installation of redundant storage silos, piping, and other process equipment would have been necessary, which would have resulted in additional capital costs. The lower cost for BrPAC made the installation of redundant systems unnecessary, thereby avoiding additional capital costs.

As a result of DTE's decision to exclusively use BrPAC, the "Reduced Emissions Fuel Mercury Benefit" is no longer shown in Exhibit A-2 since only one sorbent is planned to be used. Although this small cost difference between BrPAC and PAC was not anticipated, it is a benefit to DTE's customers since BrPAC is a very effective mercury oxidant. The ACI system is currently designed to take only one sorbent. In the event that the application frequency of REF is increased to a level at which MATS level mercury reduction is achievable without using BrPAC, then PAC may be used if found more beneficial to the customer.
4 Tr 909-910.

Based on the foregoing, along with other steps like the installation of equipment to continually monitor emissions, which allows for the most effective use of sorbents, DTE contends its expenses for mercury, particulate matter, and acid gas are reasonable and prudent. 4 Tr 911-913. As noted by DTE, none of the other parties offered any evidence to the contrary, and thus this proposed finding should be adopted.

7. REF Project Expenses

DTE's Reduced Emission Fuel (REF) Project is utilized at its Monroe, St. Clair, and Belle River facilities, and generally entails applying chemical additives to coal in order to reduce emission expenses and working capital incurred by DTE. 4 Tr 684, 912-913. The REF process was first approved in DTE's 2012 PSCR Plan as "a reasonable means of attaining maximum emission reductions for minimum costs." *In re the Detroit Edison Co.*, Case No. U-16892, June 28, 2013 Order, pg. 31.⁷ DTE has not changed the Project subsequent to the 2012 PSCR Plan, except for a modification approved in its 2014 PSCR Plan (Case No. U-17319) that constitutes "a cost benefit to DTE Electric's customers

⁷ The Court of Appeals held the Commission's approval of the Plan and 5-year forecast, including the REF Project, was "lawful and reasonable" under Act 304. *In re Detroit Edison Co.*, 311 Mich App 204, 217 (2015).

because they continue to capture the value through lower SO₂ emissions and lower allowance costs, without paying for them as an adder.” 4 Tr 684-685.

For 2016, DTE set the REF Project expense at \$5,671,000. Exhibit A-22. Mr. Marietta testified to the benefit of this expense:

[The consumption of REF] helps DTE comply with the state and federal mercury rules at the lowest reasonable cost as one component of REF is calcium bromide, which is an effective mercury oxidant. The use of REF improves efficiency of mercury removal through this mercury oxidation. At Monroe Power Plant, REF promotes mercury oxidation so that mercury can be more efficiently removed in the FGD system. Although no reduction in sorbent injection rate due to REF has been observed at this time, DTE believes that there is potential to reduce sorbent injection during periods when REF is present as the ACI systems come online and are able to be optimized. Any reduction of sorbent injection may result in an “REF Mercury Benefit” to the Fuels Companies. REF also results in other environmental benefits such as lower emissions of nitrogen oxides (NO_x) and sulfur dioxides (SO₂).

4 Tr 912-913.

Since DTE’s evidence concerning the REF Project is unrefuted, the associated expenses should be deemed PSCR costs associated with the cost of fuel burned and a disposal cost of fuel, and are reasonable and prudent.

8. Proposed 2016 PSCR Factor

Consistent with the foregoing expenses and adjustments, DTE projects its 2016 power supply costs at \$1,351,251,000, which factors in a 2015 PSCR over-recovery of \$18,808,000 that is proposed to be rolled-in to this Plan Year, and a net system requirement of 43,492 GWh. 4 Tr 926; Exhibit A-3. This translates to a unit cost of 31.07 mills per kWh, which is (0.19) mills per kWh below the 31.26 mills per kWh base unit cost.

Exhibit A-3. When the 1.068 loss multiplier is applied, the result is the maximum levelized billing factor of negative (0.20) mills per kWh, i.e. the 2016 PSCR Factor, DTE seeks in this case.

In its Application, and again in its Initial Brief, DTE requests the Commission conclude, as a Matter of Law, that Act 304 does not apply to its procurement of capacity resources not associated with any power for periods in excess of six months under MCL 460.6j(13)(b). In the 2015 Plan case, the Commission declined to make that legal conclusion, and instead held the purchases should be reviewed to determine “the reasonableness and prudence of the capacity costs acquired in accordance with the resource adequacy obligations imposed by MISO.” In re: DTE Electric Company, Case No. U-17680, January 19, 2016 Order, pg. 9. In undertaking that review, the Commission found “the capacity purchases reasonable for purposes of pre-approval under MCL 460.6j(13)(b).” Id. Consistent with that Order, capacity charges not associated with power purchased for periods in excess of six months are governed by Act 304. Further, and based on Mr. Burgdorf’s testimony, the purchases for 2016 are reasonable, and should be approved under MCL 460.6j(13).

B. 5-Year Forecast

Consistent with MCL 460.6j(4), DTE filed its forecast for the power supply requirements and costs for the period of 2016-2020. See Exhibits A-1-2, A-4-22. The same methodology utilized in projecting 2016 PSCR expenses were used in that forecast. While the Attorney General and GLREA have raised issues with the 2016 Plan, *infra*, none

of the parties challenged any aspect of the forecast, except the expenses associated with NEXUS starting in 2017. Therefore, the examination of the 5-year forecast will be limited to that project.

Recently, DTE acquired two facilities, Renaissance, a 732 MW gas fired generation facility that is forecasted to consume 6.3 Bcf of natural gas, and Dean, a 320 MW gas fired generation facility forecasted to consume 1.5 Bcf of natural gas in 2016, which will increase its natural gas requirements by 75%. *Id.*, 394-395. In addition to these facilities, DTE operates 9 other generation plants that are natural gas fired, or use natural gas as a secondary fuel. Exhibit A-26. For the Plan Year, DTE projects to consume 18 Bcf/49,500 Dth/d of natural gas at these facilities. 3 Tr 405. Transportation will be achieved through a firm contract for its Dean Plant, and a variety of other spot contracts. *Id.* 392; Exhibit A-26.

In conjunction with its current increase in natural gas generation, DTE anticipates a “fundamental shift” from coal generation to natural gas generation in the coming years. 3 Tr 388. Underlying this shift are “unprecedented environmental regulations” currently in place, such as MATS, and anticipated, such as the proposed Clean Power Plan rules. *Id.* To comply with these regulations “a significant amount of coal-to-gas switching is currently expected to occur throughout Michigan and the MISO region.” *Id.*, 390. Current estimates are that 60% of DTE’s coal-fired capacity, representing 30% of the State’s total generating capacity, will be retired by 2030. In the short-term, MISO is forecasting 41 GW of coal-fired generation will be retired in its region, causing a continued decline in its reserve margin and capacity shortages in Michigan in 2016, and across the region.

DTE projects that “more than half” of its coal fired generation facilities will be retired

by 2030. Id., 390. In its place, DTE will utilize natural gas combined cycle gas turbine (CCGT) generation based on its expectation that it will constitute the most economical source of generation. Id., 389. Ensuring affordable, adequate, and reliable supply for that generation, estimated to increase in excess of 100 Bcf per year by 2030 for DTE, is a significant concern. Concomitantly, other utilities in Michigan and the MISO region will undergo a similar shift from coal to natural gas, resulting in a 20% increase in demand in Michigan between 2015 and 2035. Id., 390. Demand for natural gas will also increase due to 20 GW of gas-fired generation coming on-line by 2020 in the MISO region. Increased demand is also driven by weather, such as the Polar Vortex in 2014, where the point was reached that some generators without firm gas supply and transportation contracts were unable to operate. This, in turn, resulted in both increased prices, \$15.66/Mcf at the MichCon City Gate as opposed to \$5.56/Mcf at the Henry Hub in February 2014, and regulatory actions imposing enhanced fuel assurance and reliability standards. Id., 391, 523.

The actual and anticipated increase in natural gas requirements led DTE to examine supply and transportation options. In regards to the former, DTE focused on Appalachian Basin gas, including Utica and Marcellus shale gas that is the largest and fastest growing supply source in North America, and priced “among the lowest in the country for the foreseeable future.” Id., 393-394. To transport that supply, DTE selected the NEXUS pipeline, a 250-mile greenfield project between southwest Ohio and DTE’s Michigan facilities, which is a joint undertaking of one of its affiliates and Spectra Energy. Id., 392.⁸

The pipeline is projected to cost \$2.2b to construct, and will have the capacity to transport 1.5 Bcf/d of Appalachian Basin natural gas from eastern Ohio to Michigan, Chicago, and Ontario starting in November of 2017. 3 Tr 393, 399; 4 Tr 131. In July 2014, DTE entered into a Precedent Agreement with NEXUS, and an amendment in September 2015. Mr. Paul testified to both:

The July 2014 Precedent Agreement with NEXUS Gas Transmission provided firm natural gas transportation for 8,500 Dth/d starting in November 2017 and increasing to 75,000 Dth/d starting on the later of May 2020 or when DTE Electric has added the required natural gas generation capacity necessary to utilize the increased volume requirement (e.g., one 680 MW CCGT with a capacity factor of at least 70%). Based on the current long-term plan, DTE expects it will meet that requirement in 2022. The cost of the NEXUS transportation is \$0.695/Dth plus a fuel rate currently estimated to be 1.9%. The Precedent Agreement specified a term of fifteen years.

In September 2015, the NEXUS Precedent Agreement was amended by modifying the amount of transportation capacity and increasing the term. The amended precedent agreement provides firm natural gas transportation for 30,000 Dth/d starting in November 2017 and increasing to 75,000 Dth/d starting on the later of May 2020 or when DTE Electric has added the required natural gas generation capacity necessary to utilize the increased volume requirement, which is currently expected to occur in 2022. The term of the initial 30,000 Dth/d is twenty years and the term of the additional 45,000 Dth/d is fifteen years.

The amended precedent agreement also adds an option for DTE Electric to extend the term of the agreement by up to ten years for 75,000 Dth/d at the same rate. Including the ten year option, the NEXUS Precedent Agreement could extend as far as 2047. This long-term, fixed rate agreement will allow for reliable and economic operation of DTE's first CCGTs for the majority of their expected lifespans.
3 Tr 397-398.

Similar to its coal acquisition policies, DTE was seeking firm natural gas transportation to ensure reliability and minimize price volatility. 3 Tr 392. To that end, Mr.

⁸ The pipeline will connect a gas processing plant in Kensington Ohio, which is in the Utica play and has ample

Paul testified NEXUS provides the:

[O]ppportunity to be an Anchor Shipper on a pipeline with access to the Utica/Marcellus shale region.... [A] new and growing production region with substantial supply and competitive pricing. Additionally, the NEXUS Open Season allowed potential customers to qualify as an Anchor Shipper for the NEXUS project by submitting a bid of 150,000 Dth/d or greater for a term of 15 years or more. Although the Company is only contracting for 75,000 Dth/d, the NEXUS Open Season allowed bidders who are affiliated with a single entity to aggregate their bids. Because the Company's gas utility affiliate, DTE Gas, is also contracting for 75,000 Dth/d, both the electric and gas utility were able to qualify for Anchor Shipper status. Anchor Shipper status provides incentives including a most favored-nations clause that assures the rate paid by DTE Electric would be the lowest rate paid by any similarly situated shipper on NEXUS.

3 Tr 395

Mr. Paul also testified the Energy Transfer sponsored Rover Pipeline and the TransCanada sponsored ANR East pipeline were not considered because neither existed at the time NEXUS was selected. 3 Tr 396. When the open season for those pipelines came up, DTE evaluated them relative to NEXUS and determined neither offered Anchor Shipping status, and the attendant fixed demand charge and most favored-nations clause, and thus would entail more cost. Id.

DTE asserts NEXUS provides its customers, and the customers of other utilities in Michigan, with a host of benefits. In this regard, it offered the testimony of Ms. Scheller and Mr. Sloan of ICF Resources, L.L.C. (ICF), which was retained "to assess the impacts of the NEXUS Gas Transmission pipeline on natural gas and power markets in Michigan." Exhibit A-25, pg. 7 of 75; 2 Tr 82, 130. That assessment is set forth in the ICF Report dated November of 2015, which, along with the testimony of Mr. Sloan, makes certain baseline assumptions and conclusions: the NEXUS receipt point is a processing plant at

connection to the Marcellus play, and DTE Gas city gate in Willow Run, Michigan. 4 Tr 640-641.

Kensington Ohio that is in the Utica play and connected to the Marcellus play by sufficient capacity; production in Marcellus-Utica went from virtually nothing 7 years ago to 15 Bcf/d in 2014; Marcellus-Utica currently accounts for 20% of all North American natural gas production, and will increase to 30% by 2035; current production is constrained by existing processing and pipeline capacity in the regions; currently 60% of gas consumption in Michigan is by residential and commercial customer, and that consumption will remain static over the next 20 years; consumption of natural gas by power utilities will double to 1 Bcf/d over the next 20 years due to introduction gas-fired generation to replace coal-fired generation; production of natural gas in Michigan equates to 13% of total demand, will remain static over the next 20 years, and thus increased consumption will have to be transported in from other regions; supply from other regions, e.g. the Gulf Coast and Mid-Continent, will be replaced with supply from the Marcellus-Utica regions over the next 20 years. Exhibit A-25, pgs. 12-22; see also 2 Tr 132-35.

The ICF Report takes the foregoing assumptions and conclusions, and utilizing its proprietary Gas Market Modeling and Integrated Planning Model analytical tools, quantifies the impact to Michigan electric and natural gas prices assuming a greenfield pipeline from the Marcellus/Utica plays is constructed. Id., 141-142; Exhibit A-25. Section 2. The Report analyzes the Michigan natural gas markets under the scenario that only the Rover Pipeline is constructed, which will add 3.25 Bcf/d of additional capacity from the Utica basin, and both Rover and NEXUS are constructed, which will add an additional 1.5 Bcf/d of capacity.⁹ Mr. Sloan testified to the results of the ICF Report:

Market Locations	Case 1 Rover Only	Case 2 Rover and NEXUS	Impact of NEXUS (Case 2 minus Case 1)	Additional Cases	
				<i>No Pipe Added</i>	<i>NEXUS Only</i>
MichCon	6.08	5.87	(0.21)	6.66	6.38
Henry Hub	6.44	6.44	0.01	6.63	6.53
AECO	5.15	4.96	(0.18)	5.62	5.39
Mid-continent	5.77	5.62	(0.16)	6.22	6.01
Chicago	6.01	5.83	(0.19)	6.55	6.29
Lebanon, OH	5.95	5.79	(0.16)	6.41	6.20
Defiance, OH	5.97	5.78	(0.19)	6.60	6.32
Dominion South Point	4.63	4.83	0.20	4.09	4.32
Kensington (NEXUS Receipt Point)	4.75	4.95	0.20	4.21	4.44

Based on the supply diversity and liquidity that will result from the 1.5 Bcf/d of capacity from the Appalachian Basin NEXUS will bring to the Michigan natural gas market, and the corresponding reduction in price for all supply identified above, Mr. Sloan projected the cost savings to all Michigan consumers is:

	Billions of Nominal Dollar,	Net Present Value of Savings, in
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⁹ Given its contracted capacity and current the current status of its application with FERC, Mr. Sloan testified "it is likely the Rover project will be completed...." 2 Tr 136. As proposed, the Rover project will provide 3.25 Bcf/d of capacity from eastern Ohio to a connection in western Ohio, and from that point 1.3 Bcf/d of capacity into Michigan, culminating on 1.0 Bcf/d of contracted capacity into Ontario. 2 Tr 136.

	2018 through 2037	Billions of Dollars ¹
1) Reduction in Natural Gas Expenditures by Michigan Residential, Commercial, and Industrial Consumers (based on weighted average cost of gas supply portfolio)	\$1.90	\$0.80
2) Reduction in Natural Gas Expenditures by Michigan Power Generators (based on gas consumed by power generators in Michigan and reduction in MichCon Citygate price)	\$1.20	\$0.50
3) Michigan Electricity Market Wholesale Energy Transaction Cost Savings ²	\$3.20	\$1.40
4) Total Impact of Nexus Pipeline on Michigan Gas and Power Consumers [1] + [2] ³	\$3.10	\$1.30
1. All net present value savings are discounted to the start of 2018 using a discount rate of 7.1%. Source: ICF 2. Wholesale power prices will be impacted in a broader area than Michigan alone, the value shown here reflects Michigan Zone 7 savings only. 3. Gas production cost savings are used as a proxy for the retail impact. To estimate the retail impact more precisely, additional analysis would be required.		

In summary, Mr. Sloan testified that

I project that the addition of the NEXUS pipeline will result in a reduction in natural gas expenditures by Michigan non-power consumers (that is, residential, commercial, and industrial consumers) of \$1.9 billion over the 20-year period from 2018 to 2037. (Line 1 of Table 2). Over the same period, I project a \$1.2 billion reduction in natural gas expenditures by Michigan power generators. (Line 2 of Table 2).

The \$1.2 billion represents the direct savings to Michigan ratepayers through utility based recovery of power supply costs (i.e., utilities recover their costs of producing power). In addition, given that gas generation is increasing, other higher cost resources would be displaced, further adding to production cost savings to the 6 utilities and ratepayers.

The \$1.2 billion reduction in gas costs to Michigan power generators also contributes to the overall Michigan electricity wholesale energy transaction cost savings of \$3.2 billion projected by my colleague Maria Scheller (line 3 of Table 2).
2 Tr 140-141.

Ms. Scheller testified to the projected savings for all Michigan electric customers resulting from NEXUS:

ICF did not perform an analysis of the impact to retail end use customers. Instead, ICF estimated wholesale savings to Michigan (Zone 7) load serving entities who on average save \$158 million per year (average nominal) between 2018 and 2037, ranging from \$29 million to a maximum annual savings of \$271 million. In total, this reflects a cumulative savings of \$3.2 billion (nominal) in total or \$1.4 billion on a net present value basis (assuming a 7.1% annual carrying charge).

However, as a regulated state, Michigan utilities who are both load serving entities and generating entities, would not pass through the full wholesale savings to retail customers. Rather, the costs savings experienced by retail end-users would be closer to production cost savings for the utility's generation fleet. As described by Mr. Sloan, ICF's estimate of savings associated with gas production is \$1.2 billion sum total for 2018 through 2037 or \$0.5 billion on an NPV basis for the same period, which is a conservative assessment of the net savings to retail end use customers. Wholesale consumers, however, do experience the full benefit of the wholesale market price reduction.
2 Tr 89

Mr. Sloan attributes two benefits for DTE customers arising from NEXUS. First, the agreement to transport 30,000 Dth/d beginning in November of 2017, with an increase to 75,000 Dth/d after some point thereafter, represents between 5% and 10% of contracted capacity, and thus "increases the likelihood that the project will be developed." 2 Tr 143. Second, utilizing NEXUS will result in natural gas cost savings to DTE:

Between November 2017 and December 2037, the cost of gas purchased at the NEXUS Kensington receipt point and delivered to Michigan via the

NEXUS Pipeline will average \$0.13/MMBtu lower than the MichCon Citygate price. Assuming DTE Electric initially contracts for 30,000 Dth per day and increases contracted capacity to 75,000 Dth per day in 2022, the reduction in DTE Electric's natural gas purchase costs attributable to holding the NEXUS Pipeline capacity would total \$79 million. These savings will have a net present value of \$22 million, for the 20 year contract period from 2018 through 2037.

2 Tr 143-144

Mr. Sloan testified the ICF forecast may understate Appalachian Basin production, and over-states future greenfield pipeline capacity from the region, which he believes "may prove difficult to build...." 2 Tr 144. If, as he believes, it comes to pass that production is greater, and capacity is lower, the value of DTE's capacity on NEXUS will be enhanced and the savings to its customers will be increased. Ms. Scheller also termed her projection as "a conservative reflection of the impact of the NEXUS pipeline...." Id., 89. Finally, the forecast does not factor in NEXUS providing firm transportation during peak winter months when prices are higher, thereby reducing natural gas expenses during colder than normal winters. Id., 144-145.

In summary, DTE asserts that between 2018 and 2038, the NEXUS pipeline will result in \$3.1 billion in savings for Michigan consumers, and \$271 million in savings for its customers. These savings will result from its obligation to provide firm natural gas transmission on NEXUS of 30,000 Dth/d beginning in November of 2017, with an increase to 75,000 Dth/d starting either in May 2020, or when DTE has electric generating capacity requiring that volume. That need for increased capacity is not expected to occur until 2022. The transportation cost is \$0.695/Dth plus a fuel rate currently estimated at 1.9%. These terms apply over the course of the 5-year Forecast at issue in this case. Thus

NEXUS is a cost item in the 5-year forecast. In its Application, DTE requests the Commission review and approve the expenses associated with the Precedent Agreement. Dkt. #1, pg. 9, ¶ L; see also 3 Tr 399.

IV.

POSITIONS OF THE PARTIES ON THE 2016 PSCR PLAN & 5-YEAR FORECAST

A. MEC/SC

The sole issue raised by the MEC/SC concerns the NEXUS pipeline component of the 5-Year forecast. Specifically, the MEC/SC contends the Precedent Agreement between DTE and NEXUS cannot be approved in this proceeding. In addition, the expenses associated with NEXUS are unreasonable and imprudent, and not otherwise allowable under MCL 460.6j. Finally, the MEC/SC argues DTE did not conform to its Code of Conduct governing affiliate transaction when it entered into the NEXUS agreement.

The first MEC/SC argument raises a legal issue: whether the Commission can approve the NEXUS agreement in this proceeding. In this regard, the MEC/SC notes that under the express language of MCL 460.6j(7), the Commission may only identify cost items in a 5-year forecast it is unlikely to permit in future proceedings. The MEC/SC contends this provision allows only for a warning to a utility that the expense may be disallowed. Conversely, the only approval process for a PSCR cost item is set forth in MCL 460.6j(6) under the reasonable and prudent test for expenses in the 12-month Plan. Because NEXUS expenses first arise in 2017, the MEC/SC argues that in this proceeding the Commission only has the authority under MCL 460.6j(7) to warn DTE the expense item

may be disallowed.

In undertaking the proper review of the 5-year forecast, the MEC/SC contends the expenses associated with NEXUS should be considered under the reasonable and prudent test in MCL 460.6j(6), which places the burden on the utility to show it “has taken all appropriate actions to minimize the cost of fuel...” See also *In re Consumers Energy Co.*, January 25, 2010 Order, Case No. U-15675, pg. 9. The failure “to pursue appropriate measures to reduce its PSCR expenses could be deemed unreasonable or imprudent conduct that could lead to the disallowance of costs.” *In re Consumers Energy Co.*, February 28, 2005 Order, Case No. U-13917, pg. 19. In addition, MCL 460.6j(6) also requires the PSCR factors not “reflect items the commission could reasonably anticipate would be disallowed under subsection (13).” That provision, which governs PSCR reconciliations, requires the Commission to:

Disallow the cost of fuel purchased from an affiliated company to the extent that such fuel is more costly than fuel of requisite quality available at or about the same time from other suppliers with whom it would be comparably cost beneficial to deal.
MCL 460.6j(13).

The MEC/SC argues that when applying these standards, the Commission should warn DTE the NEXUS expenses are unlikely to be approved in future proceedings because they are neither reasonable nor prudent, and non-compliant with subsection (13).

In support of its argument that the NEXUS expenses are unreasonable and imprudent, the MEC/SC notes that DTE never undertook a substantive analysis of the cost of purchasing firm transportation on NEXUS prior to “verbally” agreeing to participate in late

2013, or entering into the Precedent Agreement in July of 2014. Rather, as Mr. Paul testified, DTE “leaned heavily on our experts over at DTE Gas.” 3 Tr 538. DTE Gas, along with ultimately DTE and ICF, initially evaluated the cost/benefit of NEXUS by the price difference, a.k.a. basis spread, between Dominion South Point, which in 2013 was considered the best receipt point for NEXUS, and the MichCon CityGate. 3 Tr 417. Using price forecasts from 2 entities, that analysis in December 2013 showed that the price of gas on NEXUS would be higher than the market price of gas until 2017 or 2020. Id. In July of 2014, DTE Gas undertook a landed cost analysis on NEXUS and two other proposed pipelines, Rover and ANR East, which found NEXUS provided the lowest cost. 3 Tr 420. DTE obviously did not use that analysis as a factor when entering into the December 2013 “verbal agreement” with NEXUS.

In August 2015, a document prepared by DTE, and including data from ICF, indicated the basis spread between Kensington and MichCon CityGate (Kensington-MichCon) would be higher for NEXUS for every year between 2018 and 2035, except for 2028. Exhibit MEC-16, pgs. 26-27.¹⁰ In total, NEXUS was projected to cost \$54,000,000 over the Kensington-MichCon during its term. Id. The MEC/SC argues this was DTE’s first analysis of the costs associated with NEXUS, and was undertaken in anticipation of the September 2015 amendment to the Precedent Agreement. The MEC/SC contends it was not until November 2015, and in the form of the ICF Report (Exhibit A-25) filed with Mr. Sloan’s direct testimony in this case, that DTE undertook a substantive evaluation of

¹⁰ Mr. Sloan testified ICF did not prepare or review Exhibit MEC-16, but rather provided DTE the data used in that document. 2 Tr 218. Further, the receipt point identified on pg. 26, Kensington, was in error because ICF provided projected prices for eastern Ohio supply region, which includes Kensington, and Dominion South. Id.

NEXUS.¹¹ Using the Kensington-MichCon basis spread, that Report indicates the capacity on NEXUS will result in increased costs until 2024, and an overall net loss until 2030, at which point NEXUS is projected to recover the costs and result in a \$79,000,000 savings through the 2037 end of the Precedent Agreement. The MEC/SC contends that under both assessments, DTE customers will be paying higher costs under the NEXUS agreement for the entire 5-year period at issue in this case.

The MEC/SC also contends that the higher costs associated with NEXUS are, in part, a result of DTE securing greater capacity than it will need between 2017-2020. The ICF Report acknowledges that DTE will not require the transportation capacity until its 2nd planned CCGT unit is constructed and comes on-line, which will occur after the end of the 5-year period at issue in this case. Exhibit A-25. During the forecast period, DTE will only require 30,000 Dth/d of natural gas when its peakers are operating, which is 110 days a year. Since those days are typically during summer months, firm capacity is generally not a concern and other sources of supply, such as storage, capacity from a liquid trading point, or arranging with 3rd party holding transportation/storage assets to meet DTE's flexible gas requirements. 4 Tr 950. Further, DTE has not established that its plans to store or release unneeded capacity at market costs, and recouping its expenses in the process, are viable. 3 Tr 440. Rather, the record indicates that during the 5-year forecast period, and in fact through 2024, the price of gas transported on NEXUS is higher than the Kensington-MichCon basis. Thus, the sale of excess capacity through 2020 would be at a

¹¹ As noted, the Application in this case was filed on September 30, 2015, while the testimony of Ms. Scheller and Mr. Sloan were filed on November 23, along with the revised direct testimony of Mr. Paul.

price less than the purchase price, which the MEC/SC contends renders the NEXUS expenses neither reasonable nor prudent.

The MEC/SC also takes issue with DTE's contention that NEXUS provides it with reliable capacity as its gas requirements increase as future baseload CCGT units become operational. This reliability contention is belied by the September 2015 Amendment to the Precedent Agreement that provides the incremental maximum daily quantity increase to 45,000 Dth/d, triggered by the planned facilities coming on-line, is available only if "sufficient unsubscribed capacity is available...." Exhibit MEC-12. According to the MEC/SC, DTE failed to secure reliable capacity by agreeing to this provision, pointing to Mr. Paul's characterization as it being "not an ideal piece of the agreement...." 3 Tr 448. The MEC/SC also contends DTE failed to establish that it will have long-term gas requirements sufficient to satisfy its obligations under NEXUS. Thus, the 75,000 Dth/d commitment was not necessary to meet its gas supply forecast, but merely the amount DTE Gas needed another affiliate to assume to attain anchor shipper status.

The extent of DTE's future natural gas requirements are also raised by the MEC/SC. Mr. Wilson testified that while Michigan and the surrounding region is undergoing "a major shift" in its electric power resource mix, due to an aging coal-burning fleet facing ever stringent environmental regulations, it is unclear which source of generation will replace this resource. 4 Tr 943. Mr. Wilson also notes that how fast this shift will occur is unknown, especially given that load growth is projected to be slow, and advancements in technologies will influence the resource mix. Id., 943-944. Finally, it is not settled that the shift will be entirely to gas-fired generation, as advancements in wind and solar generation

fostered by advancements in storage technologies, coupled with steps taken to reduce peak load and capacity requirements, such as advanced metering and smart devices, emerge. Id., 944.

Currently, DTE is advancing gas-fired generation as a replacement for coal, but only has the 2 existing peakers, Renaissance and Dean, and has “no firm plans” to build additional gas-fired plants. Id., 948. In fact, the MEC/SC notes the only evidence on this record is DTE plans, but has not provided any details such as the location and size, to build and have operational a CCGT in 2022, followed by a second facility in 2024, and a third in 2029. 3 Tr 397-398; Exhibit MEC-45. The MEC/SC argues those plans are speculative in 2016, and were even more so in 2013 when the decision was made to obtain capacity on NEXUS, which by 2020 will be 75,000 Dth/d. Further, the capacity secured under the NEXUS agreement will not be needed until the 2nd facility is operational, which is, at best, 6 years after it goes into effect. Exhibit A-25. When DTE’s gas requirements do reach the level that makes NEXUS necessary, the MEC/SC contends other means are available to obtain that supply through Michigan’s existing, and “well endowed”, pipeline and storage capacity, along with obtaining firm capacity from nearby liquid trading point, or storage and capacity from a marketer. 4 Tr 949-950; Exhibits MEC-4 & 5.

The MEC/SC also takes issue with DTE’s contention, based in large measure on the ICF Report (Exhibit A-25), that NEXUS will provide a \$79,000,000 in savings to its customers, along with \$3,100,000,000 in savings to Michigan consumers from 2017 to 2037, because it is premised on faulty assumptions. These savings are a result of price differentials and natural gas prices up to 2037 assumed in the ICF Report. However, Mr.

Wilson testified this assumption fails to consider how pipeline networks actually expand over time: “A well-structured model would endogenously expand pipeline capacity as production and/or consumption change and price differences increase in some areas, rendering expansions on various paths economic.” 4 Tr 953. Contrary to this approach, the ICF Report used 46 identified projects, i.e. those that are in-service, under construction, pending before FERC, and announced, with a capacity of approximately 45 Bcf/d, coming on-line between 2014 and 2028. Exhibit MEC-14. However, the Report only factored in 4 generic projects, 3 of which go out of the supply region to the east, west, and south, and one within the region, coming on-line between 2025 and 2028. Exhibit MEC-14. The out-of-region takeaway capacity of these projects, which the Report states is sufficient to meet demand growth, is projected at 2.85 Bcf/d, while the Marcellus/Utica production is projected at 13 Bcf/d. 4 Tr 956.

The limitation of the generic pipeline analysis, which Mr. Wilson testified is “critical” in accurately forecasting future expansion, stems from ICF only considering expansion if/when market growth exceeded pipeline capacity. *Id.*, 955. Along the same lines, ICF’s modeling entailed exogenous expansion forecasts, i.e. manually inputted, which for a 20 year horizon will not produce a reliable forecast. *Id.*, 953; Exhibits MEC-26 and 27. Mr. Wilson testified this methodology fails to consider potential pipeline network expansions that necessarily arise when “complex markets...react to changing supply and demand”, and as a result the Report “greatly” understated how pipeline networks expand over time, and overstated the impact of NEXUS. 4 Tr 953-954. Rather, the modeling should “endogenously expand pipeline capacity as production and/or consumption change and

price differences increase in some areas, rendering expansions on various paths economic.” Id., 953. Mr. Wilson noted one such study that utilized this approach:

[T]he model used for a recent U.S. Department of Energy study of the implications of increased use of natural gas for power generation on the need for new natural gas infrastructure. [Exhibit MEC-28]. The study used the Deloitte MarketPoint North American Integrated Model (“NAIM”), which describes how the model determines pipeline expansions as follows (p. 7):

NAIM also represents the existing interstate pipeline system by pipeline segment. The model builds additional pipeline capacity when it is economic, given the computed supply-demand dynamics as well as infrastructure constraints and costs. Specifically, the model builds pipeline capacity if the basis differential across a new pipeline would be large enough to cover pipeline variable costs and recovery of upfront capital costs for expansion, while providing a sufficient rate of return. That is, the volume of natural gas flows over time must deliver sufficient after-tax margins to justify the cost of expansion.

In this model, locational price differentials over time will reflect economic decisions to expand pipeline capacity where and when it is needed.
4 Tr 953-954.

Conversely, the methodology in the ICF Report was limited to factoring in pipeline expansion only if warranted by market growth, termed “demand pull”, thereby ignoring “supply push” expansions that result from “prices, price differences, expansion costs, and profitability....” Id. 955.

Mr. Wilson also criticized the ICF Report because it failed to consider pipeline network expansions that necessarily arise when “complex markets...react to changing supply and demand”, and as a result the Report “greatly” understated how pipeline networks expand over time, and overstated the impact of NEXUS. 4 Tr 953-954. Mr. Wilson concluded these flaws render the widening basis differentials forecast in the Report,

and thus the savings DTE claims will result to its customers, unreliable:

The basis between Kensington and MichCon is well over \$2/Dth after 2020, and over \$3/Dth after 2030. The price differentials between Kensington and both Lebanon and Defiance Ohio, 200 miles away and connected by multiple existing pipelines, are also over \$2/Dth, and later over \$3/Dth. These are of course unsustainable price differences; such differentials would lead producers to seek additional expansions of the Marcellus/Utica takeaway capacity.

This failure to represent how markets would react to any capacity additions (or to their absence) results in greatly overstating the impact and value of those capacity additions that are allowed in the model, such as NEXUS. For example, comparing the scenarios with and without NEXUS (both including the Rover pipeline), ICF's modeling suggests that if NEXUS is built, twenty years later the basis differential from Kensington to MichCon will be over \$.60/Dth lower than it would be without NEXUS.

4 Tr 960; See also Exhibit MEC-7.

Consistent with the foregoing, Mr. Wilson testified the ICF Report failed to reasonably analyze pipeline expansion, and thus the impact it attributes to NEXUS on prices after 2030 is greatly exaggerated. *Id.*, 961.

To assess the likely cost of NEXUS, and belie the ICF Report's conclusion that it will ultimately result in savings to DTE customers, Mr. Wilson examined the historical price differences between the MichCon CityGate and the Kensington, Ohio NEXUS. The Report notes that Kensington prices are approximately \$0.12/Dth above Dominion South, a receipt and pricing point for Marcellus supply and reasonable proxy Kensington, and records for monthly prices for MichCon and Dominion go back to 1992. Exhibit MEC-8. Using those records, Mr. Wilson notes the prices between the two points were compatible, with MichCon averaging \$0.10/Dth less until 2013, when Marcellus supply began to grow rapidly and was transported through Dominion. The basis between 2019 and 2021 is projected at

\$0.59/Dth, and assuming it holds over time, along with the \$0.12/Dth differential between Kensington and Dominion, sets the basis of Kensington to MichCon will be approximately \$0.45/Dth. 4 Tr 962-963; Exhibit MEC-9. Applying that basis, which Mr. Wilson testified is probably inflated because it is unsustainable over time, rather than realize savings of the course of the NEXUS Agreement, DTE customers will incur \$76,000,000 (\$157,000,000 in nominal terms) in additional costs. 4 Tr 963.

Mr. Wilson testified the methodology and data from the study conducted by the U.S. Department of Energy, which as noted assumes pipeline expansion when economically justified, is the best basis to determine the impact of NEXUS. Id., 963; Exhibit MEC-28. The study sets the differential of Kensington, representing Marcellus production, and Chicago, which the ICF Report notes has higher prices than MichCon, at \$0.15/Dth. Exhibit MEC-10. Using forward prices to 2020, and the Kensington/Dominion-MichCon differential of \$0.15/Dth thereafter, represents a total cost to DTE customers of \$140,000,000 (\$295,000,000) in nominal terms from the NEXUS Agreement. 4 Tr 963. Given the increase in costs arising from NEXUS, the MEC/SC argues DTE should be warned under MCL 460.6j(7) that it is unlikely to be allowed to recover the costs associated with the project in future proceedings.

The MEC/SC also raises other concerns with NEXUS that also goes to its argument that its costs are neither reasonable nor prudent. First, it argues that even accepting DTE's contention that NEXUS will result in \$3,100,000,000 in savings to Michigan consumers and wholesale electric providers, the savings are from the construction of the pipeline. Concomitantly, any savings for Michigan customers will be subsidized by DTE customers

until at least 2030, according to the ICF Report, and 2037, according to its projections. Further, the savings DTE claims as it pertains to the cost of supply are inaccurate based on Mr. Wilson's testimony regarding the flaws in the methodology of the ICF Report, *supra*. 4 Tr 971-972. Those same flaws diminish the savings DTE claims will accrue to electric customers, in addition to:

NEXUS is forecasted to lead to incremental natural gas generation in Michigan (MISO zone 7); however, despite this incremental capacity, ICF assumes no change at all in other generating capacity as a result of the incremental gas-fired generation, over twenty years. Specifically, according to the ICF analysis, in 2030 there would be 153 MW more gas-fired capacity in Michigan if NEXUS is built than if it is not; but the total amount of all other types of capacity (coal, nuclear, renewable, other) would be unchanged.

This again is not how markets work and is totally unrealistic. If expanded access to natural gas results in additional gas-fired generation, this would increase reserve margins and depress energy prices, and the market would respond with earlier coal retirements, relatively less new renewable capacity, or other adjustments to the reduced need for capacity. Ignoring these adjustments results in greatly overstating the potential impact of NEXUS on electricity prices and costs. 4 Tr 972.

Overall, Mr. Nelson concluded:

The estimated benefits are far into the future, and inflated by ignoring how the natural gas and electricity markets would absorb the incremental capacity. If NEXUS is built, other incremental pipeline capacity into Michigan may be delayed, or flows may increase from Michigan on to Ontario, New York and New England. If NEXUS leads to incremental natural gas generation, some coal retirements will occur sooner, and other types of new generation may be delayed. The benefits are therefore doubtful, and highly speculative. 4 Tr 973.

The MEC/SC also contends that without DTE's commitment to NEXUS the project will not, in all likelihood, be completed. See 2 Tr 143, 399-400, 470; Exhibit MEC-16. In

this regard it notes that as of November 2015, NEXUS had contracted 56% of its 1,500,000 Dth/d capacity, but removing the capacity purchased its sponsors, including 150,000 Dth/d by DTE and DTE Gas, only 36% of capacity has been sold, which Mr. Wilson indicates limited “market support for the project...” 4 Tr 947. Conversely, the Rover project had 95% of its 3.1 Bcf/d capacity contracted for 15 years or longer when its application was filed with FERC in February of 2015. Id. Absent similar market support, approving NEXUS may result in short-term price suppression that:

[W]ould harm other sellers of natural gas and electricity in and around Michigan who may not be able to fully recover the lost revenues resulting from the price suppression from their customers. The Commission’s action would give pause to companies considering future investments in natural gas or electricity assets in or around Michigan, as they will be concerned that should they invest, the Commission might in the future again take administrative, out-of-market actions to suppress prices. Investors will be somewhat less likely to invest in Michigan assets in the future due to such regulatory uncertainty. While their analyses may suggest that future market prices should support expansions of natural gas and electricity infrastructure, they will be concerned that future Commission actions may again cause unexpected price suppression and below-market prices. Put another way, investors will add a “risk premium” to the revenues and profits they would need to anticipate receiving in order to invest in Michigan. Such risk premiums would ultimately result in higher costs to Michigan consumers. Accordingly, subsidizing NEXUS is a scheme that might generate short-term benefits, but be costly to consumers over the longer term.
4 Tr 965.

The MEC/SC also takes issue with DTE’s contention that it was important to obtain anchor shipping status on NEXUS, which entitles it to a lower rate should it be offered at some point to a similarly situated party, termed a “most-favored-nation” clause. See 3 Tr 395. Mr. Wilson testified this provision is unlikely to be triggered because the term “similarly situated” is so narrowly defined that it is unlikely another entity would fall under

the definition. 4 Tr 951. Therefore, rather than a mechanism that may result in a lower rate, Mr. Wilson characterized it as a promise by NEXUS not to offer a lower rate to another customer. *Id.* The MEC/SC argues any economic benefit from anchor shipper status is illusory, and does not “redeem an otherwise risky and uneconomic agreement.” Initial Brief, pg. 55.

The MEC/SC's final argument pertains to the affiliate transaction requirements in DTE's Code of Conduct. Specifically, the provisions governing “Separation” under Section II, and “Discrimination” under Section III, which it argues bans affiliate subsidization, obligates DTE to operate independently and limits affiliate compensation to the market price.¹² The MEC/SC contends the NEXUS Agreement violates these provisions in a number of regards. First, for either the first 6-8 years of the agreement, or for the entire term of the 30-year agreement, DTE will pay above market price under the NEXUS agreement. Along these lines, the MEC/SC information available when DTE entered into the agreement in late 2013, 75,000 Dth/d for 15 years, and the amendment in September 2015, should control the examination of whether the Code of Conduct was violated. In so doing, the projections in the ICF Report, which is dated November 2015, must be disregarded because it had no bearing on the decision to enter into the NEXUS Agreement.

¹² The MEC/SC cites to *In the matter of the approval of a Code of Conduct for Consumers Energy Company and the Detroit Edison Company*, , October 29, 2001 Commission Order, Case No. U-12314, as the Code of Conduct. See Initial Brief, pg. 56. However, the correct cite is Case No. U-12134, and Exhibit A to that Order is a Code of Conduct applicable to all electric utilities defined by MCL 460.652.

The MEC/SC asserts DTE has the burden of proving the agreement with its affiliate is reasonable. See *Midland Cogeneration Venture Ltd. Partnership v Public Service Commission*, 199 Mich App 286, 313-314 (1993). Contrary to carrying that burden, the MEC/SC notes DTE did not undertake any analysis of whether the NEXUS Agreement complied with the Code of Conduct, or enter any evidence on this issue. Exhibit MEC-47. Rather, the MEC/SC argues the record in this case establishes that DTE will pay more than a market rate for fuel transportation on NEXUS for 6-8 years, and in the best case not start recovering any of the losses until 2030. Further, DTE does not need the capacity unless and until it constructs two planned combined cycle gas plants in the mid-2020s, and the September 2015 amendment calls into question whether that capacity will even be available under the agreement at that point. Accordingly, the NEXUS Agreement violates §3(C) of the Code of Conduct because DTE will be paying its affiliate over market price for capacity.

The MEC/SC also argues DTE entered into the initial and amended NEXUS Agreement to, in part, ensure the pipeline is constructed. See Exhibit MEC-16, pg. 34; 3 Tr 471-473. This stated purpose, along with the fact it will result in costs above market price, constitutes a direct/indirect subsidy to an affiliate in contravention §2(B) of the Code of Conduct. Finally, §2(F) of the Code of Conduct requires DTE act independently of other entities within its corporate structure. The MEC/SC notes many instances where DTE acted in concert with DTE Gas concerning the NEXUS Agreement, including relying on its analysis and negotiations when entering into the agreement, and combining its capacity to secure anchor shipping status despite not requiring 75,000 Dth/d of supply until some point

after 2024. For these reasons, the MEC/SC contends DTE did not act independently of DTE Gas in relation to the NEXUS Agreement, and thus violated the Code of Conduct.

Based on the foregoing, the MEC/SC contends the Commission lacks the authority to approve the NEXUS Agreement in this proceeding. Rather, the Commission may only, and should, warn DTE that the costs associated with NEXUS are unlikely to be approved in future proceedings.

B. ANR

Similar to the MEC/SC, the entire focus of ANR's case is the NEXUS Agreement. In that regard, ANR argues that the relationship between DTE and NEXUS requires "special scrutiny, given the potential lack of arms-length bargaining and improper subsidization of the affiliate's unregulated operations through the utility's rates." *Midland Cogeneration Venture Ltd. Partnership v Public Service Commission*, 199 Mich App, 286, 313. In so doing, the Commission "need not assume that the fees charged by its affiliate are fair, and the utility has the burden of proving the reasonableness of its transaction with its affiliates." *Id.*, 313-314. Act 304 imposes a similar standard by requiring a utility establish the reasonableness and prudence of its power supply costs, including those involving transportation, and explain its actions to minimize those costs. See MCL 460.6j(3). The same review is to be conducted for the costs projected in the 5-year forecast, and upon that evaluation the Commission can issue a warning that the costs may not be recoverable in a future proceeding. See MCL 460.6j(7). ANR contends these standards place "a heavy burden on DTE Electric to present meaningful information..." of

the reasonableness and prudence of its decision to enter into the NEXUS Agreement, and its examination of alternatives to minimize its gas transportation costs.

Under the foregoing standards, ANR contends that DTE did not consider alternatives to access Appalachian Basin natural gas, and had it done so it would have obtained access to that supply at a lower cost. ANR also argues that the savings DTE claims will accrue from the project are over-stated. Accordingly, ANR asserts DTE has failed to establish the NEXUS Agreement is reasonable and prudent, and the Commission should not approve the project.

ANR does not dispute that DTE's objective of gaining access to Appalachian Basin supply to meet its current and projected demands is prudent. However, ANR contends the NEXUS Agreement is not the most-cost effective manner to gain that access, and DTE failed to consider existing and proposed alternatives, including entering into good faith negotiations with, or soliciting offers from, other independent carriers. Rather, DTE agreed to a monthly reservation charge of \$0.695 per Dth and an estimated fuel rate of 1.9% on its affiliate's project that results in transportation costs of \$323,000,000 for the 20 year term (\$38,000,000 between 2017 and 2022, and \$285,000,000 between 2022 and 2037). 4 Tr 639.¹³ Mr. Bennett identified two proposed pipelines that could have provided access to Appalachian Basin gas at lower costs that DTE failed to consider/analyze:

ANR East proposed to construct 240 miles of large diameter pipeline extending east of ANR's existing system from Defiance, Ohio to points in eastern Ohio, including Leesville and Clarington. ANR East was designed to provide additional access to Utica and Marcellus shale gas, with delivery into

¹³ Mr. Bennett used DTE's stated intent to have 2 gas-fired generation plants on-line by 2022, which will trigger the commitment to 75,000 Dth/d, in these calculations. 4 Tr 639. He also calculated the option to extend the agreement for 75,000 Dth/d for 10 years (2037-2047) as costing \$190,000,000. Id.

the same Michigan and Ontario markets as NEXUS, as well as to other markets connected to ANR's system. ANR East was designed to transport up to 2.0 Bcf/d of Appalachian supply from Clarington, Ohio to Leesville, Ohio and 2.4 Bcf from Leesville to ANR's existing system at Defiance, Ohio. In its July 3, 2014 open season, ANR outlined several options, with indicative rates. The open season announcement is attached as Exhibit ANR-1. The options included a transportation path from either Leesville or Clarington to various points, including Willow Run, which serves DTE Electric (called MichCon in the Open Season). Or alternatively, a shipper could choose to acquire capacity on one of two segments along that path: Either (1) Clarington or Leesville to Defiance or (2) Defiance to the same listed delivery points. Because Defiance is interconnected to other pipelines and is expected to become even more liquid once the planned infrastructure is in place, the latter options were designed to allow shippers to utilize a segment of ANR East in conjunction with other existing upstream pipelines and/or other greenfield projects being proposed to deliver Appalachian supply to points on ANR's Southeast Mainline.

Rover consists of 237 miles of gathering pipeline in Ohio, Pennsylvania and West Virginia and a 374 mile dual 42 inch pipeline system from Cadiz, Ohio to Defiance and then another 100 miles of pipeline from Defiance to an interconnection with Vector. The project can deliver up to 3.25 Bcf/d from eastern to western Ohio along a similar route as ANR East.

4 Tr 641-642.

ANR notes DTE did not consider obtaining transportation from the Appalachian Basin on either of these pipelines, let alone entering into negotiations to ascertain the feasibility of participating in the projects relative to the NEXUS Agreement. See ANR-6; see also ANR-26. In fact, in December of 2012, ANR advised DTE Gas that it wanted "a chance to compete against Nexus and that [ANR] can bring significant Utica volumes for a fraction of the cost of Nexus." Exhibit ANR-5. Despite this entreaty, ANR contends DTE Gas instead entered into negotiations with NEXUS that culminated in the December 2013 agreement to transport 75,000 Dth/d, and then began the undertaking to find an affiliate to contract for the same capacity to secure Anchor Shipper status. In July of 2014, DTE

agreed to transport that amount, but never considered ANR, Rover, or any other party that could provide that capacity. Exhibit ANR-7. Rather, it relied on NEXUS Landed Cost Analysis DTE Gas prepared in July of 2014 that merely compared the contracted rates with the published maximum rates of other carriers, which Mr. Bennett characterized as “meaningless.” 4 Tr 645; Exhibits ANR-9 and ANR-24.

Mr. Bennett testified as to the basis of that characterization:

Not surprisingly, DTE Gas’ analysis showed that NEXUS was slightly less costly than the other alternatives. This result, however, was entirely dependent on the NEXUS’ estimated fuel rate of 1.04% and Mr. Sloan’s gas price forecasts over the 15 year term of the precedent agreement. The analysis shows that the reservation charges for service on ANR East that were posted in ANR East’s open season even without negotiation are lower than the subsequently revised reservation charge both DTE Gas and DTE Electric agreed to pay NEXUS. The analysis also shows that the gas cost savings were the same for each alternative. Consequently, the sole reason the analysis showed NEXUS being less expensive is that it used an estimated NEXUS fuel rate of 1.04% while using an estimated fuel rate for ANR East and Rover of 2.00%. When that estimated fuel rate was applied to projected increases in gas prices, the result was a fuel cost for ANR East and Rover almost double that of NEXUS.

The NEXUS estimate of 1.04% was based on an estimate made by NEXUS during an early stage of the design of its project. NEXUS subsequently increased its estimate to 1.22%. The ANR East estimate of 2.00% was taken from its posted open season which was at even earlier stage of the development of this project.

4 Tr 647.

Mr. Bennett testified the rates for alternative pipelines used Exhibit ANR-9, termed the maximum recourse rate, are typically higher than what is ultimately agreed to, termed the negotiated rates arrived at through dialogue between the parties during a project’s open season. Mr. Bennett noted an example of the negotiated rate through a draft 2014 Precedent Agreement for ANR East with a reservation rate of \$0.58 per Dth for 50,000

Dth/d from the Utica basin to Michigan, despite the open season rate being set at \$0.77 per Dth. 4 Tr 649; Exhibit ANR-10. While the exact negotiated rate for ANR East cannot be quantified because DTE elected not to enter into negotiations, it is reasonable to assume it would be less than what DTE relied on in the Landed Cost Analysis.

Mr. Bennett also notes the NEXUS fuel rate used in the Landed Cost Analysis, 1.04%, was increased to 1.22% in September of 2014, and is now 1.9%. 4 Tr 651. Under that rate, “the cost of fuel on NEXUS would change from \$0.0687 per Dth to \$0.1267 per Dth based on the formula used [in Exhibit ANR-9].” 4 Tr 651-652. The reservation charge on NEXUS also increased from \$0.675 per Dth used in Exhibit ANR-9, to \$0.695 per Dth. Id., 652. Mr. Bennett calculated these rates set the cost of transportation on NEXUS at \$.8267 per Dth, while on ANR East it would be \$.8235 per Dth. Id. Concomitantly, the NEXUS reservation rate used in Exhibit ANR-9, \$0.695 Dth/d, was higher than the ANR East posted rate, i.e. before any negotiations were undertaken, of \$0.68 Dth/d. Accordingly, Mr. Bennett concluded that the basis DTE used to proceed with the NEXUS in July 2014 was flawed because it over-estimated the cost it would incur if it had elected to negotiate with ANR for transportation, and under-estimated the costs it will incur under the agreement.

Mr. Bennett also disagrees with DTE’s contention that Anchor Shipping status on NEXUS is an advantage that neither ANR East nor Rover can provide. First, he notes DTE has to transport 75,000 Dth/d to fulfill the obligation, but it currently only needs 30,000 Dth/d of capacity. The additional capacity will not be needed unless or until DTE constructs additional gas fired generation, and if that doesn’t happen its natural gas

requirements will remain the same. Exhibit ANR-12. If DTE does not need the additional 45,000 Dth/d of capacity, its Anchor Shipper status could be deemed by FERC as invalid.
4 Tr 653.

For a number of reasons, Mr. Bennett testified little, if any, benefit would result if DTE eventually does need 75,000 Dth/d of capacity:

First, in a supplemental open season posted in July 2014, shortly after the ANR and Rover open seasons, NEXUS created another status of shipper. According to this notice, a bidder in the supplemental open season could qualify either as an "Anchor Shipper" with a bid of at least 150,000 Dth/d or as a "Foundation Shipper" by submitting a bid of at least 400,000 Dth/d. See Exhibit ANR-13. While it is not entirely clear what the difference is in the two classes of shipper, it seems to me reasonable to infer that the intent is to offer a Foundation Shipper that bids 400,000 Dth/d potentially greater rate or rate-related concessions than Anchor Shippers. If true, being an "Anchor Shipper" on NEXUS is really a second class of shipper.

Second, shippers that do not qualify as an anchor or foundation shipper are not necessarily required to pay the pipeline's maximum recourse rates. In all three of the projects under consideration, the project may, and typically does, negotiate rates with each prospective shipper to meet the competition.

Third, in its application for a certificate of public convenience and necessity at FERC, NEXUS reported that all but one of the shippers that have executed precedent agreements for service on NEXUS are Anchor Shippers. NEXUS did not disclose the rates provided in these precedent agreements so it is not known how DTE Electric's rates compare to all the other shippers.¹⁴
4 Tr 654.

Based on the foregoing, and relative to greenfield projects, ANR contends that DTE did not have a substantive basis for selecting NEXUS in July of 2014, and the data it claims to

¹⁴ Mr. Bennett notes DTE has not secured least-cost shipping on NEXUS because another Anchor Shipper, Union Gas Limited, has submitted a filing with the Ontario Energy Board that indicates its rate of it has secured a rate lower than DTE: \$0.635 versus \$0.695. 4 Tr 655-656. See also Exhibits ANR-13 and ANR-14.

have relied on in making that decision was flawed. Further, DTE failed to enter into good faith discussions with the sponsors of the other proposals, and had it done so it would have secured transportation at a rate less than what it has agreed to with NEXUS. Exhibits ANR-21 and ANR-23.

ANR also contends that DTE failed to consider existing alternatives that provide access to the Appalachian Basin. For example, ANR advised DTE Gas in December 2012 that it could provide access utilizing its existing pipeline that would transport “significant Utica volumes for a fraction of the cost of NEXUS.” Exhibit ANR-5. In addition, a number of other shippers operate existing pipelines, and had available capacity in 2014, that would provide the access DTE seeks. 4 Tr 656-658; Exhibit ANR-15. As for costs, Mr. Bennett testified:

Due to the particular circumstances relating to the rapid development of Appalachian supplies, significant producer interest in getting this gas to market and the expected construction of infrastructure to access such supplies, DTE Electric need not incur the cost of capacity back to the basin to take advantage of the lower cost of Appalachian supplies. Thus, for example, DTE Electric need not purchase the upstream transportation on either Dominion, TETCo or REX because producers or marketers will hold some of that capacity and will sell the gas at the downstream Lebanon, Glen Karn and Shelbyville hubs. Due to the competition to sell gas at these points, DTE Electric could have taken advantage of the lower prices at these points and avoided the upstream transportation charges. In that event, the only transportation cost to DTE Electric would have been ANR’s \$0.20 per Dth tariff rate plus fuel. This is in contrast to the \$0.695 per Dth, plus fuel, that DTE Electric has agreed to pay to support its parent’s investment. Compared to the approximate \$19 million annual cost of NEXUS for 75,000 Dth/d, this alternative would cost only \$5.5 million annually. For the first five years on the contract when the MDQ is 30,000 Dth/d., the comparison is \$7.6 million for NEXUS versus \$2.2 million on existing ANR capacity. By contracting for transportation on ANR from these points, DTE Electric could save up to \$364.5 million depending on whether it exercises its option to extend the

term of the agreement to 2047.
4 Tr 662.

Subsequent to DTE entering into the Precedent Agreement in July of 2014, additional capacity was available on a number of existing pipelines that could transport Appalachian Basin supply with greater diversity and reliability than what it will have under NEXUS, and at a lower cost than with it will pay for NEXUS. 4 Tr 664-665; Exhibits ANR-17 and ANR18.

In fact, other Michigan utilities have been accessing Appalachian Basin supply by that means since at least 2014. Exhibit ANR-18.

ANR also takes issue with DTE's claim, made through the ICF Report, that by adding pipeline capacity to the Appalachian Basin, NEXUS will provide it and other natural gas consumers with long-term cost savings. In response to this claim, Mr. Bennett testified any savings are entirely speculative because it is not possible to forecast the price of natural gas with any degree of certainty over a 20-year period. This is particularly true of the Report's projection of:

[N]o savings for the first nine years and small savings the next four years. The bulk of these projected savings occur in years 2030-2037 when Mr. Sloan projects gas prices in the \$7.00 to \$9.00 range at the Henry Hub and price differentials between Michcon and Kensington in excess of \$1.00. In contrast, the price of gas at the Henry Hub in 2015, as shown on this exhibit, is \$3.11. Exhibit ANR-19. Projections of gas prices and price differentials that far into the future, including the projection that the price of gas will double in 15 years, are highly unreliable.
4 Tr 669.

ANR also argues that NEXUS is not the means that will result in savings to Michigan consumers. Rather, it is the access to lower-cost supply from the Appalachian Basin,

whether through existing pipelines and/or greenfield projects, that will benefit Michigan consumers. To that end, the issue is the least expensive means to obtain that access. As discussed above, ANR contends DTE's \$500 million obligation under the NEXUS agreement is not cost-effective. Rather, DTE "should be required to hold an open and transparent competition where all transportation providers can compete for DTE Electric's business, DTE Electric can choose the least cost alternative, and this Commission can assess this transparent process to ensure that DTE's ratepayers do not pay excessive costs." 4 Tr 671.

C. Attorney General

The Attorney General takes issue with both the 2016 Plan and 5-year forecast. In regards to the former, the Attorney General contends DTE's 2016 PSCR expenses should be reduced by \$36,043,000, which in turn would result in a PSCR Factor of (\$1.09) mills per kWh. The proposed reduction is derived from 5 expenses Mr. Coppola characterized as either excessive, or not adequately supported on this record. In addition, the Attorney General argues the Commission lacks the authority to approve the NEXUS pipeline expense. In the alternative to this legal argument, the Attorney General argues the expense is neither reasonable nor prudent. Accordingly, DTE should be instructed that in the future any expense associated with the project will be disallowed unless a showing is made that all options, including serious negotiations with alternative suppliers, have been examined.

The first reduction DTE proposes is \$15,037,000 from the \$727,400,000 cost of coal

projected to be burned in 2016. Underlying this proposed reduction is DTE's use of Mid-Sulfur Eastern (MSE) and High Sulfur Eastern (HSE) coal during peak periods. The basis for using this coal, instead of lower cost Low Sulfur Western (LSW) coal, is higher heating values that create more incremental value than resulting increase in fuel cost. Exhibit AG-2. Mr. Coppola agrees the MSE and HSE have a higher Btu factor, but not to the point that justifies the additional expense. Mr. Coppola testified the MSE and HSE coal produces 40% higher heat values than LSW coal. 4 Tr 987. However, the adjusted price for MSE and HSE coal, which takes into account the higher heat value, still makes the fuel 24% to 35% higher than the delivered cost of LSW. Id. Mr. Coppola estimated that if DTE burned lower-cost LSW at its facilities, in place of the projected 1,273,100 tons of MSE/HSE, it would reduce its fuel costs by \$15,037,000.¹⁵ Exhibit AG-1. The Attorney General also requests the Commission warn DTE that unless it provides sufficient justification for burning more expensive coal during the 5-year forecast period, the increased costs are unlikely to be approved.

Mr. Coppola also took issue with the amount of credit for PSCR customers from the sale of coal and coal transportation from its subsidiary to 3rd parties in 2016. For the Plan Year, DTE projects a credit of \$22,000, which is a significant reduction from the credits in 2013 (\$11.7 million), 2014 (\$14.3 million), and 2015 (\$7.9 million). Exhibit AG-3. Mr. Coppola opined DTE failed to justify the decrease, and thus proposes to impute \$11.3 million, which is the average of the credits in 2013-2015, to DTE's 2016 coal fuel

¹⁵ Mr. Coppola also testified that in addition to its higher cost, MSE/HSE coal also has higher mercury content than LSW, which will require a corresponding increase in chemicals to comply with mercury emission standards. However, Mr. Coppola did not quantify the amount of this increased expense. 4 Tr 989.

expense. 4 Tr 989-990.

Taken together, Mr. Coppola testified the use of higher cost MSE/HSE coal and underreporting of 3rd party coal credits, warrant a reduction of the 2016 coal fuel expense of \$26,337,000. Id., 990.

The next fuel cost challenged by the Attorney General is \$57,283,000 for nuclear power generation in 2016. During discovery, the Attorney General requested “all the components and calculations supporting the...” expense, which DTE refused to provide. Exhibit AG-4. Similarly, DTE refused to provide actual nuclear fuel expenses for 2014-2015, or fully explain the disparity between the expense claimed in its most recent rate case for capitalized fuel costs (U-17767) and the amount at issue in this case. Id. Without this information, Mr. Coppola testified it is “difficult to put the 2016 forecast in proper context and assess its reasonableness.” 4 Tr 992. However, he provided an alternative approach to ascertaining the reasonable 2016 nuclear fuel cost:

Company witness Colonnello in Case No. U-17767 presented a projection of \$80,299,000 for nuclear fuel which was to be capitalized during the 12 months ending December 2015 and for use in the next refueling cycle spanning 2016 and part of 2017. Exhibit AG-5 includes the exhibit [A-9] from Mr. Colonnello's testimony in that case. This capitalized cost of \$80,299,000 would be amortized over the 18-month period between the end of the last refueling cycle which occurred in late 2015 and the start of next refueling cycle which will occur sometime in mid-2017. Mr. Wines explains this process on [4 TR 783-785] of his testimony. Therefore, twelve months of the total projected capitalized amount of \$80,299,000, or \$53,533,000 should be amortized in 2016. This amount should be the reasonable amount of nuclear fuel expense for the year 2016. The unsupported Company forecast is \$57,283,000 or \$3,750,000 higher than the amount I have calculated. 4 Tr 993.

In the absence of a basis for DTE's projected nuclear fuel expense in 2016, the Attorney

General contends the \$57,283,000 amount be rejected. In its place, the Attorney General seeks adoption of Mr. Coppola's alternative approach, and the expense set at \$53,533,000.

The Attorney General also challenges the \$11,965,942 for Urea DTE claims for 2016. Exhibit A-21. Initially, DTE projected a Urea utilization rate of 2.28 tons per GWh in 2016, which Mr. Coppola noted represents significant variance from the 2.02 tons per GWh actually used in 2015. 4 Tr 994. In a response to a discovery request regarding this variance, and requesting actual Urea expenses in 2015, Mr. Coppola contends DTE revised that amount to \$10,622,130. 4 Tr 994; Exhibit AG-6. The Attorney General seeks a \$1,343,812 reduction of the Urea expense to reflect that change. 4 Tr 995.

The Attorney General challenges the adjustments of \$59,775,000 for fuel costs and \$13,763,000 for transmission costs DTE is proposing for non-PSCR sales in 2016. Those amounts are based on projected non-PSCR sales of 1,980 GWh at a rate of \$30.19 for fuel and \$6.95 for transmission. While Mr. Coppola does not take issue with either rate, he claims the projected sales volume is unreliable because DTE failed to explain or justify why the sales declined from the projection of 2,172 GWh for 2015 and 2,266 GWh in 2016 in the 2015 PSCR Plan case (U-17680) approved by the Commission. 4 Tr 995-997; Exhibit AG-7. Absent any justification for the significant reduction of forecasted non-PSCR sales in this case and U-17680, Mr. Coppola recommends rejecting the 1,980 GWh forecast, and corresponding adjustments for fuel and transmission costs. 4 Tr 996. Mr. Coppola contends the 2,172 GWh sales forecast for 2015 is more reliable, and utilizing that amount results in non-PSCR sales adjustment for fuel costs of \$65,573,000, and transmission

costs of \$15,095,000. 4 Tr 997-998. With both adjustments, PSCR expenses are reduced by \$7,130,000. Id., 998.

Based on the foregoing, Mr. Coppola determined the 2016 PSCR expenses should be set at \$1,315,208,000, which is a \$36,043,000 reduction in the amount claimed by DTE. 4 Tr 998; Exhibit AG-8. Based on those costs, Mr. Coppola recommends a PSCR factor of (\$1.09) mills per kWh.¹⁶ 4 Tr 1000; Exhibit AG-8.

As noted, the Attorney General contends that as a matter of both law and fact, DTE's proposal to secure transportation capacity on the NEXUS pipeline commencing in November of 2017 cannot be approved in this proceeding. In regards to the former, the Attorney General contends Act 304 limits the review of a 5-year forecast to identifying cost items that are unlikely to be recovered in the future through power supply cost recovery factors. MCL 460.6j(7). Thus, while the Commission may issue what are colloquially known as "Section 7 warnings" in regards to a 5-year forecast, it may not approve or reject specific cost items, such as the NEXUS transportation agreement. Conversely, the Commission can accept, reject, or amend cost items in a PSCR Plan, which covers a 12-month period. MCL 460.6j(3) and (6). Accordingly, the Attorney General argues that, as a matter of law, Act 304 does not allow approval of expenses in a 5-year forecast, and thus the Commission lacks the authority to approve the NEXUS agreement.

The Attorney General's alternative argument is that DTE has failed to establish the

¹⁶ Mr. Coppola used the Net System Requirement, Unit Cost of Power Supply and Base Unit Cost testified to by Mr. O'Neill and depicted in Exhibit A-3, to arrive at this PSCR factor. 4 Tr 998; Exhibit AG-8. He also removed a proposed reduction \$2,518,000 for limestone based on the Commission's holding in Case No. U-17767 DTE could recover it as a PSCR cost instead of through base rates. 4 Tr 998.

costs arising from the NEXUS agreement are reasonable and prudent, and will minimize future PSCR expenses. Further, DTE has failed to show its expenses associated with NEXUS, which is owned, in part, by an affiliate, do not exceed an equivalent market price or the affiliate's actual expenses. Absent such a showing, the Attorney General argues compliance with the Commission's Code of Conduct and Affiliate Transaction Guidelines, approved in U-13740 and consistent with MCL 460.10(a)(4), cannot be made. Unless and until that compliance is established, the Attorney General requests the Commission defer a decision on the recovery of NEXUS expenses.

In support of the argument that DTE has failed to establish the costs of NEXUS agreement are reasonable and prudent, the Attorney General relies on the testimony of Mr. Coppola. In general, Mr. Coppola agrees with the premise that access to the Marcellus-Utica gas basins could be beneficial to DTE's customers, and customers of other Michigan utilities. However, he contends DTE failed to consider alternatives to NEXUS, including ANR East, Rover, or existing pipelines that could provide the same or better transportation rates for supply from those basins. 4 Tr 1002; Exhibit AG-11. Instead DTE had a single discussion with both Rover and ANR East in July of 2014, and entered into the Precedent Agreement for NEXUS at the end of that month. 4 Tr 1003. Rather than undertaking a "healthy competitive process to fully screen the best deal for PSCR customers", DTE entered into what Mr. Coppola termed "a very costly, multi-year precedent agreement with NEXUS." 4 Tr 1003-1004. Had DTE engaged in a competitive process, it could have very well negotiated rates and terms, including the length of the commitment and capacity requirements it claims as a basis for not utilizing ANR East or Rover, more favorable than

the NEXUS agreement. Id., 1002-1003.

In addition to its failure to consider all of its transportation options, Mr. Coppola also opined the cost savings from NEXUS claimed by DTE are overstated and based on flawed assumptions:

In reviewing Mr. Sloan's and Ms. Scheller's calculations of the cost savings to DTEE customers and the entire State of Michigan, it is evident that the entire cost savings impinge on the assumption that gas prices in the Marcellus-Utica basins will remain lower than prices in the other gas basins where DTE currently obtains natural gas. This assumption goes against the basic laws of economics. Gas prices like most other commodities typically move toward an equilibrium point as gas producers and marketers in all producing areas will re-price their product in order to retain or gain market share.

On the other hand, if producers in other basins were able to maintain higher prices, it would accord producers in the Marcellus-Utica basins the opportunity to increase their prices up to the equivalent delivered price paid by utilities and other gas buyers in gas consuming areas of the country. It would be irrational for producers in the Marcellus-Utica basins to under-price their product and keep prices low in the long-term once they have gained sufficient market share.

The same view was voiced by Mr. Paul¹⁷ in his response to a discovery request asking if he agreed that basin-on-basin competition will likely result in gas prices declining in existing gas basins:

"Basin-on-basin competition will likely result in lower gas prices in existing basins relative to the pricing in those basins if the competition did not exist, assuming the new basin's production is at a low enough cost. However, despite continuing production growth in the Utica/Marcellus region and elsewhere, it is likely that gas prices will increase in the future. Witness Sloan discusses current and forecasted natural gas markets in more detail in his supplemental direct testimony Exhibit A-25." [Footnote omitted].

As shown in the graph 1 on page 44 of Mr. Sloan's Exhibit A-25, his assumption is that the Marcellus-Utica gas accessed by NEXUS would be priced at an increasingly beneficial differential over the next 20 years to the

¹⁷ Matthew T. Paul, DTE's Executive Director – Generation Optimization & Corporate Fuel Supply. 4 Tr 386.

price of gas currently accessed from other gas basins in North America and delivered to the MichCon Citygate station by other pipelines. This is not a credible scenario. Although I understand Mr. Sloan has developed a sophisticated price forecasting model, the results of his model go against price economic theory and common sense. Instead, it is more likely that the price difference will shrink over time so that the delivered cost of gas to Michigan from competing pipelines will approach zero as markets reach equilibrium. This is not to say that there may not be price inefficiencies in the short-term that should not be exploited. However, this would occur whether DTE contracts for pipeline capacity with NEXUS or other pipelines that have access to the Marcellus-Utica region.

4 Tr 1006-1007.

Mr. Coppola notes that the purported savings from NEXUS are also not evident when considering the increased gas costs in the 5-year forecast. Specifically, pipeline reservation costs for 30,000 Dth/day of capacity on NEXUS of \$1,300,000 for November and December of 2017, and \$8,100,000 annually for 2018-202. 4 Tr 1009. When capacity increases to 75,000 Dth/day in 2022, Mr. Coppola testified the annual cost will be \$20,600,000, with a total cost of \$355,000,000 between 2017 and 2037. Id.; Exhibit AG-12. Currently, DTE's supply purchases includes interstate transportation charges, and DTE is not projecting "any significant reductions from prior years" through 2020, leading Mr. Coppola to conclude the NEXUS agreement will not decrease costs or result in savings from lower gas prices. 4 Tr 1009. In fact, significant savings would not be realized until 2030, which is 13 years after the agreement begins, and even that is speculative. Id., 1009-1010.

Currently, DTE has what Mr. Coppola characterized as "necessary gas supply arrangements to supply its existing gas-fired generating plants...." 4 Tr 1011; Exhibit AG-11. In its place, DTE is proposing the NEXUS agreement that will increase those costs

in the next 5 years, and no assurance exists that any subsequent savings from having access to the lower-cost Marcellus-Utica supply will off-set those increases. 4 Tr 1012. Accordingly, Mr. Coppola suggests the Commission reject the NEXUS agreement, which the Precedent Agreement allows DTE to rescind without penalty, and require that it fully explore through good-faith negotiations all options, and select the one that offers the best rates and terms. Id., 1012-1013.

D. GLREA

Through the testimony of Mr. Crandall, the GLREA contends that DTE's proposed 2016 PSCR Plan and 5-Year Forecast are "flawed and erroneous" because they "exclude consideration of customer owned solar PV [Photovoltaic] energy resources." 2 Tr 59. Mr. Crandall argues that customer owned generation affects DTE's electricity demand forecast and that "DTE must project the effect of these independent customer actions on its load to be served." Id., 68. Mr. Crandall believes that the failure to include customer owned generation has led DTE to overstate its energy demands, and that had such consideration been included in the Plan and Forecast, the result would have been a lower PSCR factor. Id., 59, 65. Moreover, both Mr. Crandall and GLREA view such an approach as consistent with the federal Clean Power Plan, Act 304, Act 295, and Governor Snyder's 2015 Energy Strategy and Directives, all of which show a "clear direction toward enhanced renewable energy." Id., 63.

DTE freely admits that it "does not forecast customer owned renewable generation in the PSCR Plan." Exhibit GLREA 6. Still, Mr. Crandall does acknowledge that DTE takes

renewable energy it owns or has purchased through PPAs into account when developing the Plan and Forecast, as required by Act 304. Between 2016 and 2017, DTE projects that it will add 15 MW of Company-owned renewable energy generation. Exhibit GLREA 4. Thereafter, DTE only projects to add 1 MW of Company-owned renewable energy generation through 2020. Id. DTE also projects that renewable PPAs will remain stagnant at 101 MW throughout the 5-year Forecast. Id. Further, while DTE's renewable energy output is projected to increase from 3,050 GWh per year to 3,297 GWh per year between 2016 and 2017, its renewable energy output is only projected to increase to 3,300 GWh per year by 2020. Exhibit GLREA 5.

Mr. Crandall contends that DTE should include customer owned generation because it has been expanding significantly of late and will continue to do so. In support, Mr. Crandall points to a National Renewable Energy Laboratory study showing a significant drop nationally in median per installed watt pricing, including both residential and non-residential installations, from \$12 in 1998 to \$4 in 2014. 2 Tr 65; Exhibit GLREA 2. Mr. Crandall then draws the inference that "[t]he price decrease stimulated a rapid upswing in the amount of solar PV installed." 2 Tr 65. As further evidence of industry growth across the nation, Mr. Crandall points to a Solar Energy Industries Association report, which indicates that residential solar PV in particular comprises "the fastest-growing sector in . . . U.S. solar." 2 Tr 66. The same report shows solar in general being installed at a record pace; 7.2 GW in 2015, roughly a 16% increase from 2014, as well as 16 GW in 2016, roughly a 120% increase from 2015. 2 Tr 66-67; Exhibit GLREA 3. In Michigan, Mr. Crandall points to a Commission report showing approximately a 30% increase in the

amount of customers participating in DTE's net-metering program from 9,578 in 2013 to 12,378 in 2014. 2 Tr 67.

Mr. Crandall testified that, should the Commission approve the Plan and Forecast without a downward adjustment in the PSCR factor, DTE will have to import more fossil energy than necessary, which would be an "economic drain on businesses and the citizens of the State of Michigan." Id., 64. In fact, Mr. Crandall provided several projections based primarily on current national solar PV market trends that he expects to continue "at least well into [DTE's] five-year PSCR plan horizon." Id., 67. For 2016, Mr. Crandall estimates that customer owned PV generation will offset approximately \$6.7 million in fuel and MISO associated costs, which reduces the 2016 PSCR factor by \$0.04 per MWH. For 2019, he estimates that customer owned PV generation will offset approximately \$12.1 million in fuel and MISO associated costs, which would reduce the 2019 PSCR factor by \$0.17 per MWH. Id., 69-70. Although Mr. Crandall estimates that the fuel costs between 2016 and 2019 would stay roughly the same, he estimates that customer owned PV generation would increase in value over that same period due to increases in MISO's market capacity. Id., 71.

As a result of this perceived flaw in both the Plan and Forecast at issue in this case, Mr. Crandall makes several recommendations. Foremost, the Commission should adopt his proposed downward adjustments to the PSCR factor. 2 Tr 72. The Commission should also direct DTE to discuss and analyze its strategy to implement solar energy in the Plan and Forecast, especially concerning available opportunities and benefits of expanding solar energy in DTE's service area. Id. Finally, the Commission should direct DTE to be

more transparent with both the Commission and the public at large when it comes to solar energy. Id.

E. Staff

While it did not offer any evidence in this regard, Staff asserts in its Initial Brief that it reviewed DTE's case regarding the NEXUS agreement, and believes it is "reasonable" and the record "supports the approval of the transportation volume, duration of the terms for the various transportation capacity levels, and the maximum rate." Dkt. # 105, pg. 3. However, this "approval" does not extend to the actual contract, but only the terms of the Precedent Agreement, which DTE did not enter into the record or offer for approval. Id., pg. 4. When the contract is finalized, Staff contends it should be submitted to the Commission for approval.

V.

ANALYSIS

A. 2016 PSCR PLAN

1. Attorney General

The Attorney General has seeks to have PSCR expenses reduced by \$36,043,000 based on 5 expenses that are purported to be excessive or not supported by the record. Using that reduction, the Attorney General seeks to have 2016 PSCR expenses set at \$1,315,208,000, and the PSCR factor of (\$1.09) mills per kWh. See Exhibit AG-8. In response to all of the proposed reductions, DTE argues in its Reply Brief that the testimony

of Mr. Coppola, upon which the Attorney General's challenges are predicated, should be afforded little weight because he lacks the requisite qualifications to opine on electric utility operations. Mr. Coppola's education focused on accounting and finance, his professional experience was with natural gas utilities, and his consulting work was primarily in regards to the issues pertaining to those utilities. See 4 Tr 1014-1023.¹⁸ As a general proposition, certain issues that Mr. Coppola offered opinions on, such as DTE's coal burning and nuclear power generating operations, are arguably beyond the scope of his expertise, while others would seem to fall under his expertise.¹⁹ However, the scope of a witness's expertise should be addressed during a hearing, where the party offering the testimony can lay a foundation and the other party can conduct voir dire examination and/or cross-examination of the witness, rather than raising the issue in a Reply Brief. In any event, while DTE's request that none of Mr. Coppola's opinions be afforded any weight is overly broad, there is some merit to the contention that little weight should be afforded to portions of his testimony.

Of the proposed reductions sought by the Attorney General, \$26,337,000 is from the cost of coal, and includes \$15,037,000 arising from the cost of MSE and HSE coal, adjusted for heat value, as opposed to lower-cost LSW coal, during peak periods. The remainder stems from the reduction of the credit for the sale coal from a DTE subsidiary to

¹⁸ Mr. Coppola has never testified in a DTE PSCR Plan or Reconciliation case. According to his curriculum vitae, Mr. Coppola has testified or analyzed filings in PSCR Plan and Reconciliation cases, rate cases involving electric utilities. 4 Tr 1016-1023. However, the bulk of his participation as an expert witness was in regulatory proceedings pertaining to natural gas. *Id.*

¹⁹ Mr. Coppola did not directly address the operations of DTE's nuclear facility, but rather contends it failed to provide adequate information, i.e. "the source, calculation, and components...", of its projected nuclear fuel expenses, and offered an alternative method for calculating those expenses. See 4 Tr 992. Thus, while Mr. Coppola is not qualified to opine on nuclear power generation, he can, to some extent, opine on the accounting aspects of those operations.

3rd parties. The Attorney General contends the significant reduction of the credit from previous years was not justified on this record, and \$11,300,000 should be imputed to DTE and the PSCR expenses adjusted accordingly.

In regards to the use of coal during peak periods, the limits of Mr. Coppola's expertise concerning DTE's operations are evident when considering Mr. Yurko's testimony that Mr. Coppola's "conclusion is based upon an erroneous premise that by simply comparing the prices of two fuels and their associated heat content values, one can determine the economic value in the electric market place of operating with a certain percentage of one fuel compared to the other." 4 Tr 726. In other words, a number of factors go into the type of coal and/or blends of coal burned on a given day besides the relative market price between MSE/HSE and LSW. For example, the increased heat value of MSE/HSE coal allows units to operate at higher generating levels, and depending on MISO electric market prices will result in incremental value that exceeds the price difference with LSW coal. Id., 726-727.

Mr. Yurko also noted the operational considerations that go into the coal blends:

All DTE Electric's existing coal units, except for Belle River Units, were originally designed to burn bituminous or eastern coals, which are higher in heat value (>12,000 BTU/lb) and lower in moisture (<8%). These units were not originally designed to burn Low Sulfur Western (LSW) coals, which are sub-bituminous coals with much lower heat value (<9,500) and higher moisture (1 >20%). There are many other differences in the characteristics of the coals that can impact the performance of the units when utilized at different blends such as ash fusion temperature, iron content, etc. It is often a combination of these characteristics that results in the MW output limitations to safely, economically and reliably operate the units at varying blends.

One example of a key limitation associated with the Low Sulfur Western coals is the typically lower ash fusion temperatures, which tend to result in furnace (boiler) pluggage issues due to the accumulation of molten ash in areas of the furnace that can cause significant operational problems over time. Another limitation is the maximum amount of coal that can be processed by each coal mill. The real MW output limitation that DTE's coal units face due to coal mill limitations can be easily demonstrated using the maximum tons/hr each coal mill can process on a unit.

For a Monroe unit, each coal mill is able to process about 100,000 to 115,000 lbs per hour. Let's use 110,000 lbs/hr as an example. The Monroe units have 7 coal mills each. If all mills are in service, the unit can process a maximum of 770,000 lbs/hr of coal. Utilizing Western Coal (LSW) with a heating value of 8,800 BTU/lb and Eastern Coal (HSE) with a heating value of 12,900 at a 70% LSW / 30% HSE blend (70/30), results in a 14% higher blended heat value of 10,030 BTU/lb compared to the 8,800 BTU/lb for 100% LSW (100/0). The unit can operate with approximately a 14% higher MW output on the 70/30 blend compared to the 100/0 blend because the mills are providing that many more BTUs/hr to the boiler.

Stated another way, the unit is limited to a lower 1 MW output level at the 100/0 blend because the coal mills can only process a certain tons/hour of coal. This can be seen by the following calculation of the MW output at the maximum coal volume (ton/hr) that can be processed. Let's assume for this simple example that the heat rate is the same at both blend / MW output combinations. (In real life it would be a little higher at the 100/0 and lower MW output state).

Net MW out at **70/30 Blend:**

$$(770,000 \text{ lb/hr coal} \times 10,030 \text{ BTU/lb}) / (10,000 \text{ BTU/KWh} \times 1,000 \text{ KWh/MWh}) = \mathbf{772 \text{ MW}}$$

Net MW out at **100/0 Blend:**

$$(770,000 \text{ lb/hr coal} \times 8,800 \text{ BTU/lb}) / (10,000 \text{ BTU/KWh} \times 1,000 \text{ KWh/MWh}) = \mathbf{678 \text{ MW}}$$

In summary, coal mills are a major limiting factor and the unit would suffer a net MW output loss of 95 MW at 100/0 blend vs 70/30 due to the lower heat value of the blend, just due to coal mills alone, if all coal mills are available. Since all coal mills are not available 100% of the time, the situation is dynamic. Even if it were feasible to invest in more coal mill capacity, other unit constraints would still limit the unit on the same order of magnitude and in some cases by a greater amount than the coal mills. So, if the Company were to eliminate the use of eastern coals as Witness Coppola suggests, then this MW loss would have significant negative consequences resulting in a higher PSCR expense due to the lost energy and capacity market value of

this output.
4 Tr 727-729; See also Pratt, 4 Tr 690.

Mr. Yurko went on to note, and provide a detailed supporting analysis, that if the Company did not use MSE/HSE coal, i.e. only burned LSW coal as implied from Mr. Coppola's recommendation, the 2016 PSCR expense would actually increase by \$19,200,000 due to lost net energy market value, with a long-term increase of \$22,500,000 attributable to lost MW output capacity. Id., 730-734.

DTE also takes issue with Mr. Coppola's contention that it failed to provide a basis for its coal blending program, citing to the daily blending options and selection of its blends based on market conditions projections in 2016 it provided in discovery. See Id., 727, 730; Exhibits A-37 & A-38. DTE also notes the contention that the use of MSE/HSE results in higher emission chemical treatment costs is misplaced because mercury emissions are managed by equipment installed at its Trenton Plant, and for other facilities, the costs are built into the blending model. 4 Tr 736.

Based on the foregoing, the Attorney General's argument that the 2016 PSCR expenses should be reduced by \$15,037,000 based on the use of MSE/HSE coal, instead of LSW coal, cannot be accepted. Rather, the record indicates DTE takes into consideration a number of other factors besides the relative price of the coal in making its determinations of what blends to use. Further, eliminating the use of MSE/HSE coal, which is the effect that would result if the Attorney General's recommendation is adopted, would actually increase PSCR expenses in 2016, and beyond.

The second component of the Attorney General's argument concerning coal is the

credit for 3rd Party transactions with Midwest Energy Resources Company (MERC). As noted, Mr. Coppola recommends the credit DTE projected for 2016, \$22,000, is significantly less than what was recorded the previous 3 years. As such, the Attorney General seeks \$11,300,000, the 3-year average, be imputed to DTE as credit for coal services. Mr. Pratt testified the significant reduction in this credit is a result of a corresponding reduction in MERC's 3rd party coal and coal transportation volume and revenues. Id., 694. Specifically, MERC is expected to transport 2,300,000 tons of coal in 2016, which is half of the actual volume in 2015, and almost 60% less than the actual volume in 2014. Id. Mr. Pratt attributed the reduction to "decreasing demand for coal and coal transportation..." occurring throughout the industry due to environmental regulations and shifting generation to natural gas and renewable. Id. For example, MERC no longer provides supply and transportation for Consumers Energy's Cobb and Weadock facilities because they were retired in April of 2016, and a contract to ship 1.5 million tons of coal to Europe expired in 2014. Id., 694-695. Thus, merely looking at historical performance and ignoring current market conditions is not a valid method to project 2016 3rd party coal services revenues. Accordingly, the Attorney General's contention that the projected \$22,000 credit for these services is understated cannot be accepted.

The Attorney General also seeks to have the nuclear fuel cost set at \$53,533,000 because the amount projected in the Plan, \$57,283,000, is not supported by the record. This would result in 2016 PSCR expenses being reduced by \$3,750,000. DTE notes that the remedy for not complying with a discovery request, which the Attorney General contends underlies this proposed reduction (Initial Brief, pg. 26), is a Motion to Compel.

The Attorney General did not seek relief in that manner. Further, DTE contends the information sought in discovery (Exhibit AG-4) regarding nuclear fuel expenses is proprietary information of one of its 3rd party fuel suppliers, and is prohibited from sharing the information unless and until the Attorney General obtains a license from that entity .

Mr. Wines testified to that point:

FUELMACS© computer software is used for nuclear fuel amortization determinations (i.e., DTE Electric disclosed in the cited discovery response that FUELMACS© is utilized to determine nuclear fuel expense). If Witness Coppola would have obtained lawful access to FUELMACS© software or its documentation report, then he may have gained understanding of how nuclear fuel amortization methods work in FUELMACS©.

DTE Electric and many other utilities use FUELMACS© to develop the total nuclear fuel expense forecasts similar to what is tabulated in Exhibit A-1 for projected nuclear fuel expenses. In general, its use in support the development of Exhibit A-1 in this case may be described as follows:

Col (e) Nuclear Fuel Expense: Total fuel expenses shown in column “(e)” of Exhibit A-1 is the sum of columns “(c)” and “(d)” for each line in the Exhibit A-1 table.

Col (c) – “Fuel Amort” is the fuel amortization column values and are from FUELMACS© software calculation results. FUELMACS© is proprietary software licensed from Energy Resources International. FUELMACS© calculates fuel expense along with many other parameters.

DTE Electric prepares the input for FUELMACS© from various sources (like other utilities in the nuclear industry). The inputs with the greatest impact on projected fuel expense include the following:

1. Amortized costs are based on heat generated by the nuclear fuel. The heat data is input for each operating cycle and is based on fuel cycle analysis performed by the Fermi nuclear fuel bundle fabricator.
2. The projected operation of Fermi is also an input. Proposed refueling outage dates and reactor capacity factors are FUELMACS© inputs.

Another major input is the remaining value of the fuel currently in the reactor and the expected costs of fuel for future cycles. Projected new fuel costs are estimated based on contract terms (e.g., known prices, known pricing functions) and projections of Uranium, Conversion, and Enrichment service prices, and Fabrication service costs.
4 Tr 790-792

Based on this testimony, DTE did not withhold information from the Attorney General concerning nuclear fuel expenses.

This leaves the projected nuclear fuel expenses for the PSCR Year. Mr. Wines testified that it is not necessary to have the proprietary information to evaluate that projection:

I would choose to take an annual expense value of \$48,171,126 [from the 2014 PSCR Reconciliation] and divide by 7,792 [from the 2014 PSCR Reconciliation] to obtain approximately 6.18 \$/MWHr. Then I would compare 6.18 \$/MWHr to 2016 PSCR Plan Exhibit A-1 for 2016 and would find that 6.00 \$/MWHr in the 2016 PSCR Plan is a smaller rate than the actual nuclear fuel expense from approximately nine-month old data from end-of-year 2014. Because of the smaller cost rate and small change in cost rate approximately 3% the consistency to an independent and final calculation of expense rate would lead me to believe material differences did not exist using this method.

In the alternative, I could assume that a non-outage year scaled up by an estimation factor that represents approximately 18-month Operational Cycles and assumed 40-day duration refuel outages (i.e., $1 + [365/2 - 40] / 365 = 1.39$) and multiply it by a year with no refuel outage (e.g., \$57,283,000) and arrive at a value of approximately \$79,650,000 and this could be used as an estimate of an average front-end cost of all fuel utilized for an estimated Cycle of Operation. Now, if \$79,650,000 is a small difference in benchmark data, actual data, or projected/estimated cash flow values, an external observer may conclude that there is likely to be a negligible build-up or draw-down of component cost values considered as work-in-progress or inventory.

Please understand that these are rules-of-thumb that may be used to obtain ballpark estimates of nuclear fuel cost and/or nuclear fuel expense information. These rules of-thumb cannot provide a precise calculation

because more information must be known prior to predicting nuclear fuel expense more accurately.
4 Tr 794-795.

Mr. Wines also explained that the variance in this expense from previous forecasts, such as the 5-year forecast in the 2015 PSCR case that forms the basis of Mr. Coppola's challenge to the 2016 projection, are neither noteworthy nor significant. Rather, they can be attributed to "the timing and duration of each Operating Cycle's core design, the projected nuclear fuel cycle front-end costs, and the remaining value of the reused nuclear fuel due to expected differences between actual operation and earlier projections." Id., 794.

Mr. Wines also testified that Mr. Coppola's methodology for projecting nuclear fuel expenses has three fundamental flaws. First, Mr. Coppola relies on the nuclear fuel capital expenditure in DTE's 2015 PSCR Plan based on actual costs as of September 2014, rather than the updated projection used in this case based on actual costs as of September 2015. Mr. Wines also testified Mr. Coppola failed to consider that unamortized nuclear fuel is amortized based on heat generated to create electricity, a point he made in his direct testimony. See 4 Tr 782. In so doing, Mr. Coppola "neither applied nor demonstrated any utilization of applicable subsections of 18 CFR 101 Section 120 and 18 CFR 101 Section 518 in his calculation." Id., 797. Next, Mr. Wines took issue with Mr. Coppola use of a time factor in his amortization calculation, and thus did not consider refueling outages or energy production, despite the fact "front-end costs based on as-built information are a direct input

and subject to amortization and expensed over about four Operating Cycles and cannot be exactly known years in advance.” Id. In sum, Mr. Wines opined Mr. Coppola’s methodology is “functionally unrelated to the expectations of Title 18 of the Code of Federal Regulations”, and it, along with the ultimate calculation of nuclear fuel expenses in 2016 he made under it, “are flawed.” Id.

DTE notes that Mr. Wines testified to the methodology he employed in developing the projected nuclear fuel expense of \$57,283,000 in 2016. Exhibit A-1. This expense consists of front end costs, i.e. the material used in the process that are amortized to PSCR expense over the life of the fuel, and regulatory costs, which currently is \$0/MWh of generation. 4 Tr 784. Underlying the expense are “reasonable” assumptions Mr. Wines made concerning the operation of Fermi 2:

Projected electrical generation is consistent with a 95% capacity factor when operating at power and with forty-day duration refuel outages occurring approximately every 18-months. Additionally, nuclear fuel bundle loading quantities and nuclear fuel cycle component prices are fuel cost projection inputs as well.

4 Tr 784-785

Next, the projected generation from the facility, which incorporates planned losses due to refueling outages along with a reasonable amount of unplanned losses, are determined to establish the energy requirement for the fuel cycle. Id., 785. The expense of material, such as Uranium, enrichment services and fuel fabrication, to meet that requirement is amortized over the fuel cycles to arrive at the projected nuclear fuel expense for the PSCR Year. Id., 785-786.

Mr. Wines opined on both the methodology used to arrive at the projected nuclear

fuel expense, along with the reasonableness and prudence of that amount:

Fermi has been successful in managing its Uranium, enrichment services and fabrication fuel expenses for many cycles. Industry benchmarks for Uranium and enrichment pricing include the long term market indicator, DOE Energy Information Agency data, and industry surveys. Fermi's projected fuel expense and nuclear fuel cost component purchase prices are competitive when compared to the industry benchmarks and this trend is expected to continue. Fabrication pricing does not have an equivalent benchmark. Fermi controls fabrication costs with engineering time, which maintains small reload batch sizes. Thus, the number of fuel bundles remains optimal, which lowers fabrication costs and reduces the required amount of Uranium and Enrichment services. Projected prices and the total unit price are expected to remain consistent with component market price indications, all of which have experienced significant changes in past years. I am confident the Company can continue to manage these expenses effectively going forward and, therefore, I believe the projected fuel costs for Fermi are reasonable and prudent.

4 Tr 786.

Based on the foregoing, the methodology underlying Mr. Coppola's proposed adjustment of 2016 nuclear fuel expenses is flawed, and thus cannot be accepted. Conversely, Mr. Wines set forth a comprehensive basis for how DTE's projected nuclear fuel expense was arrived at, and the steps taken to effectively manage that expense.

The next expense challenged by the Attorney General is for Urea, which Mr. Coppola contends was adjusted by DTE while this case pending from \$11,965,942, to \$10,622,130. See Exhibit AG-6. However, that contention is not supported by DTE, which notes that when this case was filed on September 30, 2015, the projected Urea expense was based on data available at that time. Subsequently, and in response to a discovery request submitted in March of 2016, the lower amount was used because complete 2015 expenses were available. DTE notes that under Act 304 a PSCR Plan must be filed 3

months before the start of a PSCR Year, and the Commission then evaluates the decisions underlying that Plan in order to ascertain whether they are reasonable and prudent. MCL 460.6j(3) and MCL 460.6j(6). In effect, DTE argues Act 304 necessarily requires an examination of expenses based on what was known at the point the Plan is filed, and any subsequent development that changes the expense is properly addressed in the PSCR reconciliation process. See MCL 460.6j(12).

In making its argument, DTE notes that the day after a Plan is filed, and every day thereafter, additional actual data becomes available that will change a projected expense. This is a valid point under the regulatory framework established under Act 304: whether the expenses were reasonable and prudent based on the information the utility had when the projection was made. See generally *Attorney General v Public Service Commission*, 161 Mich App 506, 517 (1987). Therefore, the fact that Urea expense changed once actual 2015 data was available does not mean the projection of that expense in a PSCR Plan filed in September of 2015 is, as a matter of law, unreasonable or imprudent. Rather, the inquiry is whether the projected expense is reasonable and prudent based on the information available with partial data from 2015.

Mr. Yurko testified the projected 2016 Urea expense contained in the Plan is based on a ratio of tons per GWh generated by DTE's Monroe units, and entails estimating a number of variables, including unit availability, heat rate, market prices, and fuel blends, and fuel burned. *Id.*, 736-737. Further, the price of Urea is volatile, and is primarily influenced by agricultural demand, as opposed to its use by utilities in environmental control processes. In considering all of these factors, DTE projected Urea expense in 2016

at \$11,966,000. Mr. Coppola does not contend any of the underlying data used in arriving at this amount was incorrect, or the methodology was somehow flawed. Rather, he relies on the simple proposition that the amount actually expended in 2015 was lower, and thus the expense in 2016 should be the same. Mr. Yurko effectively established the flaws in that contention:

The 2015 actual price [of Urea] was \$345/ton compared to the \$336/ton forecasted or about 3% higher. Furthermore, he ignored 2015 Actual Monroe Plant generation of 16,150 GWh compared to the 2016 Plan Generation of 15,651 GWh or about 3% higher. The net of all these factors, had Witness Coppola fully applied his own improper method of using all the 2015 actual data, available many months after the filing, to adjust projected urea expense, his proposed PSCR Expense adjustment for alleged inaccuracies in projecting urea expense would be revised downward from \$1,343,812 to approximately 1/2 that amount or closer to \$700,000, which is a de minimus amount when one considers that DTE Electric's forecast for urea expense was based upon best available data three (3) months prior to the start of the 2016 PSCR Year.

4 Tr 737.

Based on this evidence, the Urea expense proposed by Mr. Coppola cannot be accepted. Rather, the record indicates that the projected Urea expense in the Plan is reasonable and prudent based on the data available when it was formulated.

The final issue raised by the Attorney General concerns the proposed adjustments for fuel and transmission costs for non-PSCR sales in 2016. The Company arrived at the amounts in the Plan using, in part, projected sales of 1,980 GWh. The Attorney General characterizes projected sales in this case as a significant decline from projection in DTE's 2015 Plan, and no justification was provided to support the reduction. Absent that, the Attorney General argues the 2015 non-PSCR sales forecast of 2,172 GWh should be used

to set projected fuel and transmission costs, which translates to \$7,130,000 reduction in PSCR expenses.

In response, DTE argues it provided more than adequate support for its sales forecast, and the methodology it utilized in doing so was the same it employed in 2015. 4 Tr 831. As a general matter, Mr. Leuker, who is the Manager of Corporate Energy Forecasting, testified to the formulation of the sales forecast, which takes into account “various economic, technological, regulatory, and demographic factors that have affected them in the past.” 4 Tr 820. In addition, variables, such as motor vehicle production, are entered into regression calculation, and projections are formulated for four major rate categories that have numerous sub-category equations. Id. All of the projections are then subject to explanatory variables, including a number of economic factors. Id., 822-825. Mr. Leuker testified that lower sales projection in 2016 is primarily due to expected lower automobile and steel customer operations. Id., 831.

Mr. Burgdorf testified the non-PSCR sales forecast is an input, with an adjustment for losses based on a Commission approved factor, of data received from Corporate Forecasting Group formulated under the methodology testified to by Mr. Leuker. Id., 875. Based on this testimony, the Attorney General’s contention that DTE failed to support the non-PSCR sales forecast cannot be sustained. Further, Mr. Burgdorf explained why even if Mr. Coppola’s adjustment of sales to non-PSCR customers, i.e. R-10 and D8 interruptible and non-metered customers, is accepted, PSCR expenses will not be reduced:

The R10, D8, and unmetered customer rate classes have been approved by the Commission and the Company does not control how many MWhs are actually used by these customers. These rates are charged on actual Non-

PSCR Customer load and not the forecasted volumes in the PSCR Plan. The actual cost to serve these customers will be reconciled in the 2016 PSCR Reconciliation proceeding and carved out of the cost to serve PSCR customers.
4 Tr 876.

Based on the foregoing, the proposed adjustment of non-PSCR sales, and corresponding reduction in PSCR expenses, sought by the Attorney General should be rejected.

2. GLREA

In effect, the GLREA's challenge to both the Plan and 5-year Forecast rests upon its contention that DTE failed to consider the impact that customer owned solar PV generation will have on its demand. Had it properly included this generation, and the corresponding benefits GLREA ascribes to this generation, the PSCR factor would be lower. Accordingly, the GLREA requests the Commission find the Plan and 5-year forecast with respect to solar capacity incomplete and inaccurate, and direct DTE to rectify the situation in future cases by properly analyzing solar generation.

Except for a portion discussed below, Mr. Crandall's testimony does not refute the data underlying the Plan and 5-year Forecast, or propose a disallowance of any specific expense that would warrant a downward adjustment to the PSCR factor. Rather, Mr. Crandall focuses on the expansion of solar energy as an industry nationwide, as well as the increase in the amount of DTE's customers participating in its net metering program. According to Mr. Crandall, those two factors warrant not only an adjustment to the PSCR factor, but also a more robust discussion and analysis of DTE's solar energy strategy, including customer owned generation, in future Act 304 cases.

DTE argues the GLREA's recommendations should be rejected under the doctrine of collateral estoppel, which bars relitigation in a new proceeding of an issue decided in a previous proceeding involving the same parties, and applies to proceedings before the Commission. See *Attorney General v Mich Pub Serv Comm (In re Consumers Energy Co for Rate Increase)*, 291 Mich App 106, 122 (2010). DTE lays out the test for collateral estoppel, and why it is satisfied in this proceeding:

Collateral estoppel is warranted when the following three prerequisites are satisfied: 1) an issue was actually litigated and determined by a valid and final judgment, 2) the same parties had a full and fair opportunity to litigate the issue, and 3) there was mutuality of estoppel. [Footnote omitted]. In addition, the doctrine of collateral estoppel is generally applicable to administrative agency proceedings. [Footnote omitted]. Finally, an issue fully decided in an earlier Commission proceeding is barred by the doctrine of *collateral estoppel* from re-litigation in a subsequent proceeding unless the party wishing to do so establishes by new evidence or a showing of changed circumstances that the earlier result is unreasonable. [Footnote omitted].

In this case, all three prerequisites for *collateral estoppel* are satisfied. The first prerequisite of *collateral estoppel* is satisfied because GLREA's recommendation that DTE Electric's PSCR Plan or five-year forecast should reflect customer-owned PV solar energy was raised by GLREA in DTE Electric's 2015 PSCR Plan Case No. U-17680, but rejected by the Commission's final order for that case.¹¹ The second prerequisite of *collateral estoppel* is satisfied because both GLREA and DTE Electric fully litigated this issue in Case No. U-17680 based on similar evidence presented again in this case. Finally, the third prerequisite for *collateral estoppel* is satisfied because both DTE Electric and GLREA are bound by the Commission's final order issued in MPSC Case No. U-17680. For these reasons alone, GLREA's recommendation in this case should be rejected by the Commission under the doctrine of *collateral estoppel*.

In addition, GLREA has not presented any new material evidence or shown any change in circumstances that the Commission's final order in MPSC Case No. U-17680 was unreasonable and warrants a different outcome in this case. In fact, GLREA sponsored even fewer exhibits in this case compared to last year's 2015 PSCR Plan case. [Footnote omitted]. Of the exhibits sponsored by GLREA in this case, one exhibit is simply Mr.

Crandall's resume (GLREA Exhibit GLR-1) while three (3) exhibits are DTE Electric's exhibits and a discovery answer that simply reiterates DTE's position (GLREA Exhibits GLR-4 through GLR-6). The remaining two (2) exhibits sponsored by GLREA in this case provide information on a nationwide basis, but otherwise make no specific reference whatsoever to Michigan, much less DTE Electric's PSCR customers (Exhibits GLR-2 and GLR-3). Therefore, Exhibits GLR-2 and GLR-3 should be given zero evidentiary weight because they are not relevant to either the 2016 PSCR Plan or 2016-2020 five-year forecast, which ultimately concern DTE Electric's PSCR customers pursuant to Act 304, MCL 460.6j, *et seq.* [Footnote omitted].

Reply Brief, pgs. 5-7. Dkt. #115.

DTE has established that the doctrine of collateral estoppel is available in a proceeding before the Commission. Concomitantly, DTE makes a valid point that the GLREA is essentially making the same arguments in this case as those that were decided in Case Nos. U-17319 and U-17680.²⁰ However, in this case, Mr. Crandall is proposing specific adjustments to PSCR expenses in the Plan and 5-year forecast. See 2 Tr 69-71. For this reason, the recommendations of the GLREA should not be rejected under the doctrine of collateral estoppel.

Turning to the merits of the GLREA's argument, no authority is provided to require DTE to consider customer owned solar PV generation in the Plan and Forecast that would result in the adoption of Mr. Crandall's proposed adjustments. To the contrary, it is well-established that in formulating a Plan and Forecast, "the utility is not required to pursue anything other than existing sources of electrical generation under MCL 460.6j(3) and (4), and that an Act 304 case is not an appropriate vehicle for holistic long-term resource

²⁰ This point is further established when considering the side-by-side comparison of Mr. Crandall's testimony in U-17680 and this case, along with the similarity between exhibits entered in both cases. See Reply Brief, pgs. 4-5, Dkt # 115.

planning.” Case No. U-17680, January 19, 2016 Order, pg. 3 (citing Case No. U-16892, June 28, 2013 Order, pg. 30; and Case No. U-17319, March 6, 2014 Order, pg. 12).

Rather than pursuing the relief sought in this case, the GLREA's arguments are seemingly relevant in the biennial review of the Renewable Energy Plan (REP) DTE is required to submit under Act 295. MCL 460.1001, *et seq.* The GLREA notes DTE filed a June 30, 2016 application to amend its REP approved in Case No. U-17793, now docketed as Case No. U-18111, in order to reflect considerable additions of solar and wind capacity to DTE's resource mix. Reply Brief, pg. 4, Dkt. #117. Nevertheless, the fact that DTE is seeking to amend its REP does not support the GLREA's position, but merely affirms that at this juncture Act 295 cases, not Act 304 cases, are the proper vehicle to address the renewable energy issues it has raised in this case.

The GLREA also relies upon Governor Snyder's 2015 Energy Strategy and Directives as evidence of a clear policy direction towards increased reliance upon renewable energies such as solar. Initial Brief, pgs. 19-21, Dkt. #109. However, the Commission is bound to review the Plan and Forecast under the existing provisions of Act 304 as enacted by the Legislature, which may decide at some point to enact the Governor's recommendations. However, as the Commission held, “the direction that Michigan will take in addressing its energy future is uncertain, thus, the Commission is reluctant to make significant changes to the requirements for PSCR plans and forecasts.” Case No. U-17680, January 19, 2016 Order, pg. 5 (citing Case No. U-17319, May 14, 2015 Order, pgs. 14-15). The GLREA acknowledges as much in its Reply Brief, stating that “the

Commission has essentially deferred making findings or rulings on said matters pending the resolution of energy policy matters before the Legislature.” Reply Brief, pg. 3, Dkt. #117. Again, until the Legislature resolves those matters, the GLREA should participate in the biennial review of DTE’s REP under Act 295.

For the foregoing reasons, the GLREA’s contention in this case that the Commission should require DTE to not only consider customer owned solar PV generation in its PSCR Plan and Forecast, but also to make adjustments to the PSCR factor accordingly, should be rejected as a matter of law. DTE already incorporates its Commission approved REP into the Plan and Forecast, and the GLREA has failed to point out any expenses in the Plan that are unreasonable or imprudent under Act 304, or any expenses in the Forecast that may not be approved in future Act 304 cases.

Based on the foregoing, none of the challenges raised by the Attorney General or the GLREA regarding the 2016 PSCR Plan can be sustained. Therefore, the Company’s proposed findings of fact regarding its 2016 PSCR Plan should be adopted, and the Plan should be approved.

B. 5 YEAR FORECAST

With the exception of certain issues raised by the GLREA that are discussed above, the points of contention regarding the 5-year forecast pertains to the expenses for NEXUS that arise in November of 2017. In general, DTE requests approval of those expenses, while MEC, ANR and the Attorney General all contend such approval is not available in this proceeding. Rather, these parties argue the expenses are neither reasonable nor prudent,

all the Commission may do is issue warning under MCL 460.6j(7) (Section 7) that they are unlikely to be approved in a future proceeding.

The examination of NEXUS must begin with the legal issue of what Act 304 allows in regards to the treatment of projected expenses in a 5-Year forecast. First, Act 304 requires a utility file:

[A] 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs, in light of its existing sources of electrical generation and sources of electrical generation under construction. The forecast shall include a description of all relevant major contracts and power supply arrangements entered into or contemplated by the utility, and such other information as the commission may require.

MCL 460.6j(4).

Upon the receipt of the forecast, the Commission:

[S]hall evaluate the decisions underlying the 5-year forecast filed by a utility pursuant to subsection (4). The commission may also indicate any cost items in the 5-year forecast that, on the basis of present evidence, the commission would be unlikely to permit the utility to recover from its customers in rates, rate schedules, or power supply cost recovery factors established in the future.

MCL 460.6j(7).

Under these provisions, a 5-year forecast should “provide insights into load, fuel, and power supply trends and options in a more forward-looking manner....” *In re Detroit Edison*, Case No. U-17319, March 6, 2014 Order, pg. 12. However, the review of the forecast cannot be conflated to the point that it results in “protracted litigation of policy and technical matters that would delay the PSCR proceeding and would be better handled in a traditional rate case, certificate of need proceeding, or a collaborative planning effort among the Commission and stakeholders.” *Id.* Rather, the process entails a general

review of projections of power supply requirements, and the utility's proposed methods to meet those requirements. In performing that review, the Commission may, at its discretion, issue what is termed a Section 7 warning. That warning is not, standing alone, a bar to recovery of the cost item when it arises at some point in the forecast period. Rather, it constitutes an evaluation of the underlying decisions that, if dictated "on present evidence...", makes future recovery "unlikely." Thus a Section 7 warning is fairly considered as advisory, and as more information becomes available or circumstances change, recovery of the cost item may, at some point in the future, be allowed.

This leaves the issue of whether a cost item in a 5-year forecast can be "approved" as DTE seeks for NEXUS costs in this case. See Dkt. #1, pg. 9, ¶ L; see also 3 Tr 399. As noted, Act 304 does not provide express authority to approve a forecast or its components. Under the cardinal rule of statutory construction, if the language is unambiguous it must be applied as written. See *Koontz v Ameritech Services, Inc.*, 466 Mich 304, 312 (2002). Even if ambiguity were to be found, implied authority to approve a cost item in a 5-year forecast is not possible when considering the comprehensive process established in Act 304 for the review of a PSCR Plan, and the result of that review. Specifically, Act 304 identifies the information that must be provided in a Plan, establishes a reasonable and prudent standard for reviewing that information, and requires the Commission to ultimately approve, disapprove, or amend the Plan. See MCL 460.6j(3), (5), and (6). The Commission's ultimate determination concerning the Plan then has a substantive legal effect in the recovery of power supply costs through the reconciliation process. See MCL 460.6j(15). Act 304 does not provide the same "approval" process for a cost item in a

5-year forecast, but merely provides for the Section 7 warning that may be changed at some point in the future.²¹

In light of the express provisions providing for a comprehensive review of a Plan relative to a 5-Year forecast, along with the significant difference in the effect of the ultimate determination, Act 304 does not allow for the “approval” of a 5-year forecast, or a cost item in that forecast.²² Rather, the forecast must be examined to determine whether, based on the evidence on this record, it contains a cost item that is unlikely to be approved in a future proceeding. In so doing, a reasonable and prudent standard is utilized. See *In re Upper Peninsula Power Company*, Case No. U-17911, September 23, 2016 Order, pg. 6.

Having established the nature of a review of a 5-year forecast under Act 304, along with the standard of review, the inquiry turns to whether a Section 7 warning should be issued for the costs associated with NEXUS as sought by ANR, MEC/SC, and the Attorney General. As a preface to that inquiry, it is important to consider the purpose of NEXUS, and the context upon which DTE became a participant in the project. It is axiomatic that as coal-fired generation decreases in the coming years, replacement generation must be secured. DTE has determined, and no credible evidence was entered on this record to the

²¹ Given the substantive differences, utilizing the concepts underlying the review of a Plan to the review of a 5-year forecast, i.e. approving a cost item in the forecast, is contrary to the doctrine of varying expressions: “[W]hen the legislature has used certain language in one instance and different language in another, the indication is that different results were intended....” *French v Mitchell*, 377 Mich 364, 384 (1966).

²² “Unlike the PSCR plan, the forecast is not approved by the Commission....” *In re Detroit Edison Company*, Case No. U16892, Order on Rehearing, (August 29, 2013), pg. 5. In construing MCL 460.6h(7), which applies to GCR Plans and has similar language as MCL 460.6j(7), the Commission held it does not “approve” a 5-year forecast, examines it to determine if the “projections constitute ‘a reasonable and prudent hypothesis of future events’ in light of known and foreseeable circumstances [citation omitted]”. *In re Michigan Gas Utilities Co.*, Case No. U-10982 (September 12, 1996), pg. 13.

contrary, that natural gas generation is the most economical form of replacement. Given this, it is incumbent for DTE to obtain future sources of supply of natural gas, and entirely reasonable for it to do so with the relatively abundant and inexpensive production from the Appalachian Basin. The issue is whether its proposal to transport that supply on NEXUS is reasonable and prudent in light of the cost involved versus the alternative means of transportation advanced by the other parties.

As set forth under the discussion of the 5-year forecast, DTE's involvement with NEXUS began in November of 2013, and culminated in the July 2014 Precedent Agreement. See Dkt. #115, pgs. 44-46; See also 3 Tr 414-415. In December of 2013, DTE relied on DTE Gas' analysis and determined NEXUS "would be a good long-term opportunity that would yield access to low cost gas supplies." Id., 417. The involvement of DTE Gas is understandable given that it has technical expertise in securing natural gas supply. Id., 415. Further, DTE had been involved with NEXUS since the open season in October of 2012, and had bid for 75,000 Dth/d a month later with the intention of ultimately aligning it with an affiliate bid of the same capacity to secure Anchor Shipper status. This, in turn, would ensure receiving a subsequent lower rate secured by a similarly situated shipper, and a fixed demand charge that is not subject to change due to increased construction costs.

In November of 2013, DTE began evaluating NEXUS for its supply needs, and the next month the decision to proceed was reached based, in part, on an economic analysis prepared by DTE Gas. 3 Tr 416-417. DTE Gas, which also decided to participate with NEXUS in December 2013, submitted a bid for 75,000 Dth/d during the open season in

November 2012, and had been in negotiations with NEXUS regarding additional capacity since September 2013. *Id.*, 415-416. DTE entered into a Precedent Agreement with NEXUS on July 31, 2014. Under that agreement, DTE secured firm transportation of 8,500 Dth/d of natural gas starting in November of 2017, and increasing to 75,000 Dth/d by the later of May 2020, or when DTE had natural gas generating capacity to utilize that capacity, which at the time was projected as 2022, at a cost was \$0.695/Dth plus a fuel rate of 1.9%. The agreement also conferred Anchor Shipper status on DTE. In December 2013, DTE Gas entered into a “partially executed Precedent Agreement...” that Mr. Paul testified was contingent on DTE committing to also transport 75,000 Dth/d. *Id.*, 418.

1. ANR

Both ANR and DTE put forth different timeframes for when the decisions underlying the agreement to participate in NEXUS were made. ANR argues the decisions were made right up to the time the Precedent Agreement was executed on July 31, 2014, while DTE contends the decision was made in December of 2013. Mr. Paul’s testified DTE’s agreement at that time was verbal, and given effect through DTE Gas’ “partially executed...agreement...” that was contingent on DTE on commitment. 3 Tr 418, 487. The record is devoid of any evidence concerning what terms and conditions were made in the “verbal agreement”, and thus it cannot form a basis that DTE had concluded it would participate in NEXUS in December 2013. Mr. Paul also testified that DTE Gas’ commitment to NEXUS in December 2013 was not conditioned on DTE’s commitment. *Id.*, 507. In any event, any claim that DTE was somehow committed to NEXUS by DTE Gas’

partial agreement in December 2013 is tenuous. Further, to accept DTE's contention that in December of 2013 it had decided to commit in all respects to NEXUS, would also require accepting that it did not negotiate the terms of the Precedent Agreement that was executed 7 months later. Given that it subsequently negotiated the September 2015 amendment to that agreement, and during that process NEXUS "dug their heels in on..." the potential limitation of the Increased MDQ of 45,000 Dth/d, it is difficult to accept that similar negotiations did not occur in 2014. *Id.*, 447-448; see also Exhibit MEC-12, pg. 35. Thus while DTE may have made a decision on some level to participate in NEXUS in December 2013, most likely to commit to eventually transport 75,000 Dth/d to secure Anchor Shipper status, its commitment was not formalized until it executed the Precedent Agreement on July 31, 2014, during the supplemental open season. Exhibits MEC-12 and ANR-13.

Based on the foregoing, the import of the July 31, 2014 Precedent Agreement is that the events leading up to it, and the agreement itself, constitute "the decisions underlying the 5-year forecast...." MCL 460.6j(7).²³ As a general principle, Act 304 requires a determination of whether the action under consideration was reasonable and prudent at the time it was made. See *Attorney General v Public Service Comm*, 161 Mich App 506, 517 (1987). The decisions at issue in this case went to obtaining transportation capacity from the Appalachian Basin, and were made between November 2013 and July of 2014.

²³ The effect of that Precedent Agreement, and subsequent amendments, in relation to the review of a 5-year forecast under Act 304, is discussed below.

As discussed, securing long-term supply from the Appalachian Basin was certainly prudent in light of the on-going shift from coal-fired generation to natural gas generation. Further, the decision to secure access from a greenfield pipeline was also prudent, which even ANR impliedly asserts by arguing that access should be through its pipeline, ANR East, or Rover. However, the open season for both of those pipelines was in July 2014, which was when DTE was finalizing its negotiations with NEXUS. When most, if not all, of those decisions to pursue access from a greenfield pipeline were made, neither of those were viable alternatives for the simple reason they did not exist. In fact, ANR was aware of DTE Gas' intent to obtain transportation capacity on NEXUS in December 2012, and while it indicated an intent to compete for that business, it did not offer a concrete project for over a year and a half. Exhibit ANR-5. Therefore, ANR's contention that it was unreasonable to not consider ANR East or Rover at that point cannot be accepted. Rather, the record indicates that when DTE began evaluating its options in November 2013 and decided to negotiate with NEXUS in December 2013, it was the only pipeline that had held an open season. When ANR East and Rover had their open seasons in July of 2014, DTE declined to participate because it was committed to NEXUS. 4 Tr 419. There is a lag between when the ANR East open season started, July 3, 2014, and when the Precedent Agreement was executed on July 31. Exhibits ANR-1 and MEC-12. Thus the DTE Gas landed cost analysis of July 2014, which compared NEXUS with ANR East and Rover, should have at least been considered to some extent by DTE before it entered into the

Precedent Agreement.²⁴ Exhibit ANR-9. Since the analysis indicates that NEXUS was the least-cost greenfield pipeline, it would not be a basis to find DTE's decision to proceed with NEXUS was unreasonable.

ANR contends the ultimate conclusion in both the July 2014 and December 2014 studies are, for a number of reasons, unreliable and should not be considered. First, ANR takes issue that they were prepared by DTE Gas, but offers no legal basis for rejecting them merely for that reason. Since DTE Gas possesses knowledge and experience in all aspects of the natural gas industry, it would be curious if DTE did not rely on that organization as it began the process of expanding its natural gas generation. ANR also criticizes the July 2014 study because it relies on the published rates for ANR East and Rover, and contends that if DTE had entered into negotiations with the sponsors it would have secured lower rates. DTE cites a number of instances of communication with ANR, starting in 2012 with DTE Gas when NEXUS was first broached, and again in 2014 when ANR was promoting ANR East. At no point did ANR offer, or give any indication it would accept, reduced rates on ANR East.²⁵ Most importantly, for the purpose of the July 2014, landed cost analysis, ANR advised DTE Gas to use its posted rates from the ANR East open season. See 2 Tr 322-325, 4 Tr 644. This is consistent with DTE's contention that negotiations with ANR would be futile given its experience that it always charges maximum

²⁴ DTE Gas also prepared, for the purpose of its GCR Plan case (U-17691) a landed cost analysis in December 2014 that obviously had no bearing on DTE's decisions concerning NEXUS. Exhibit ANR-24. The July 2014 landed cost analysis is Exhibit A-34 in that case (2 Tr 320), and was reviewed in formulating this PFD.

²⁵ Mr. Bennett testified that DTE did not seek to negotiate a lower rate with ANR. 4 Tr 644. But he does not indicate that ANR offered a lower rate, and there is no evidence on this record that ANR made any affirmative step in this regard.

rates and will not provide discounts given its dominance in, or in the words of Mr. Lawshe “stranglehold” on, the Michigan market. 2 Tr 343-344.

Based on the foregoing, the July 2014 landed cost analysis prepared by DTE Gas is relevant to DTE’s decision to participate in NEXUS. The fact the study used published rates for ANR East and Rover in comparing costs with NEXUS was reasonable, and the methodology utilized in reaching its conclusions were valid. See 2 Tr 320-323. Further, the data used in that study was, at the time it was issued in July of 2014, the best available information. 3 Tr 325-327. Based on the July 2014 landed cost analysis, NEXUS was the least-cost option relative to ANR East and Rover when the Precedent Agreement was executed on July 31, 2014.

ANR also argues that DTE could obtain transportation capacity from the Appalachian Basin through existing pipelines (brownfield) at a lower cost than NEXUS. DTE counters this argument by noting the brownfield pipelines requires supply be purchased in western Ohio and Indiana, and then transported to Michigan. 2 Tr 175. Conversely, NEXUS allows supply to be purchased in the production region, and then transported directly to Michigan. Id., 176. The benefit of NEXUS is the portion between the production region and western Ohio, which would be lost if ANR’s alternative was pursued. Id., Exhibit A-36. This evidence supports DTE’s argument that the direct connection with the Utica Marcellus region provided by NEXUS is preferable, from a cost perspective, to securing transportation on brownfield pipelines.

ANR also makes a number of other arguments concerning NEXUS. First, it contends the benefit of Anchor Shipper status is questionable because DTE may not

require 75,000 Dth/d of supply for the foreseeable future. However, it is clear that DTE is in the process of shifting its source of generation from coal to natural gas, and the process will accelerate in the coming years. 3 Tr 407-408. Thus it is reasonable and prudent for DTE to begin securing supply for that generation, and NEXUS, including the 75,000 Dth/d commitment, is an important step in that regard. ANR also contends any benefit from Anchor Shipper status is greatly diminished by the terms of a transportation contract another entity has negotiated. DTE make a valid point that the contract ANR cites to, a 150,000 Dth/d commitment from Union Gas, has a variable rate, while DTE has a fixed rate, rendering any comparison irrelevant. 3 Tr 412-413. The evidence indicates that at this time, DTE's Anchor Shipper status entitles it to a \$0.695/Dth rate, which is 21% less than the \$0.8833/Dth maximum tariff rate. 3 Tr 411-412. This rate, which Mr. Paul accurately characterizes as "significantly discounted", along with the most favored nation provision, makes Anchor Shipper status beneficial to PSCR customers as DTE becomes ever more reliant on natural gas generation.

ANR's final argument is DTE over-stated the benefits that will result from its commitment to NEXUS, particularly the benefits identified in the ICF Report. Exhibit A-25. That Report is dated November 2015, meaning it played no role, relative to the 5-year forecast, in the decisions underlying DTE's commitment to NEXUS between November 2013 and July 2014. Further, the Report quantifies the benefits of NEXUS through 2037, which is well beyond the scope of the inquiry in this case: whether the cost items associated with NEXUS in 2017-2020 should be the subject of a Section 7 warning. A recommendation concerning the future review of NEXUS is made below. For the purposes

of ANR's argument, suffice to say the Report reinforces the evidence DTE presented concerning its decisions between November 2013 and July 2014. Specifically, generation is transitioning from coal to natural gas throughout the industry, the Appalachian Basin is a burgeoning area of low-cost and abundant natural gas, and a greenfield pipeline/pipelines from that region will provide cost benefits to DTE customers. *Id.*, 2 Tr 132-139.

2. MEC/SC

The MEC/SC raises a number of the same issues as ANR. For example, MEC argues that the NEXUS agreement cannot be "approved" through the review of a 5-year forecast under Act 304, and whether it was proper for DTE to rely on the analysis of DTE Gas in considering whether to participate in NEXUS. The MEC also takes issue with the benefits DTE claims flow from having Anchor Shipper status. The analysis of those arguments, *supra*, apply equally to the MEC/SC's contentions.

The MEC/SC raises two issues regarding NEXUS that are intertwined. The first is the NEXUS agreement will result in higher costs than DTE is projecting over the 20-year term. The second is the higher costs is a violation of DTE's Code of Conduct governing affiliate transactions. Underlying both arguments is the MEC/SC's contention that the information DTE relied on in deciding to participate in NEXUS all indicted the price of gas will be considerably higher than the market price, set as the Kensington-MichCon basis, until either 2035, or in the best case 2024, and even then the costs will not be recouped until 2030. Under the methodology Mr. Wilson contends properly projects the economic effect of NEXUS between 2017-2037, the project will result in increased costs of either

\$76,000,000 (\$157,000,000 in nominal terms), or \$140,000,000 (\$295,000,000). See 4 962-963; Exhibits MEC-8, 9 and 28. DTE counters that beginning in 2018, and throughout its 20-year term, NEXUS will result in \$3,100,000,000 of savings to Michigan consumers of natural gas. Included in that amount is \$350,000,000 in savings for DTE customers, which will come from \$79,000,000 in savings of gas purchase costs, and \$350,000,000 in savings from lower natural gas costs resulting from the direct access of Appalachian Basin supply. See 2 Tr 138-144; Exhibit A-25.

It has been previously determined that under the review required by Section 7, the substantive evidence indicates that in late 2013, DTE reasonably began considering obtaining long-term natural gas supply from the Appalachian Basin to meet its future generation requirements. A vital component of that process was securing firm transportation of that supply from the production region through a greenfield pipeline. Accordingly, the decisions, up to and including the July 31, 2014 Precedent Agreement, were reasonable and prudent, primarily because it represented the least-cost option for accessing supply from the production region at that time. Accordingly, a Section 7 warning should not be issued for the costs associated with NEXUS in the 5-year forecast.

Should the Commission deem it appropriate to consider the project beyond the 5-year forecast, DTE's projection that NEXUS will result in cost savings to its PSCR customers over the term of the agreement is also compelling. It is axiomatic that projecting natural gas costs over a 20 year period, which under the 2015 amendment to the Precedent Agreement could be a 30 year period, is problematic. Even more so, projecting pipeline expansions over that period of time, which is an important factor in quantifying the

impact of NEXUS, is “difficult” because for a number of economic and non-economic considerations. 2 Tr 158. Having said that, the methodology underlying the ICF Report’s conclusion that NEXUS will result in lower natural gas costs for DTE, relative to the projected basis from Kensington and MichCon city gate, is sound. See Exhibit A-25, pgs. 64-68. Conversely, and relative to the ICF methodology, the alternative modeling Mr. Wilson used that forms the basis of MEC/SC’s contention NEXUS will result in increased costs is questionable. Specifically, Mr. Wilson’s opinion is premised on the assumption that pipeline capacity out of the production region will match production growth, which is unrealistic and not supported by recent events. 2 Tr 160. As Mr. Sloan notes, and as the ICF Report assumes, the price spread between Marcellus/Utica and other markets will fluctuate as take-away capacity and production effect each other. Id., 160-161. Based on this record, the ICF Report is more reliable than the methodology underlying the MEC/SC’s

For the most part, the MEC/SC and ANR argue the NEXUS agreement violates DTE’s Code of Conduct because it will result in excess costs. However, the record indicates DTE has established that it was reasonable in committing to NEXUS, and that its projections that the commitment will likely lead to future cost savings to its PSCR customers are valid. Therefore, the costs associated with NEXUS are not excessive, and thus the arguments to the contrary do not support the contention the agreement violates the Code of Conduct. See MCL 460.10a(4). The parties also argue the NEXUS agreement constitutes an improper cross-subsidy of an unregulated affiliate, and thus a violation of the Code of Conduct. DTE is correct that it is not contributing either directly, or indirectly, toward the construction costs of NEXUS, i.e. subsidizing the project. Based on

this record, the NEXUS agreement is a reasonable means to obtain firm interstate transportation of natural gas from the Appalachian Basin at market price in order to meet DTE's planned expansion of its combine cycle generation fleet. While NEXUS is an unregulated affiliate, the agreement does violate the Code of Conduct

3. Attorney General

As DTE notes, the only argument the Attorney General advances regarding the 5-year forecast, beyond those raised by the MEC/SC and ANR, goes to the reliability of the ICF Report and its conclusions regarding cost savings. Specifically, the Attorney General argues the Report mistakenly assumes the price of Marcellus/Utica natural gas will remain lower than other regions, and as a result its conclusions are unreliable. See 4 Tr 1006-1007. However, Mr. Sloan effectively refuted this argument by explaining it is contrary to "fundamental economic truths about the real gas market...", and is not supported by "historical natural gas prices..." that reflect actual market conditions. 2 Tr 176-178. Accordingly, the Attorney General has not provided any basis for the relief sought in this case, including the rejection the purchase of transportation capacity on NEXUS. See Initial Brief, pgs. 22-23, Dkt # 108.

VI.

CONCLUSION

Based on the foregoing, and viewed solely from the perspective of DTE's PSCR customers, both the MEC/SC and ANR contend, in general, that NEXUS will result in

significant excess costs between 2017 and 2047, while DTE contends it will lead to significant savings. The relative merits of each contention are discussed above. Beyond that, it is important to note these contentions are made in the relatively limited confines of the review of a 5-year forecast submitted under Act 304, which does not provide for the approval of the cost item. Rather, under Act 304 the sole issue is whether a warning should be issued that the recovery of the \$7,600,000 annual transportation expenses incurred under the NEXUS agreement between 2017 and 2020 is unlikely. As DTE notes that expense has “relatively little impact on a future PSCR factor...” given that it constitutes 0.56% of the total projected annual PSCR costs that range between \$1.4 billion and \$1.5 billion for that period. Exhibit A-4; Initial Brief, pg. 38, Dkt. #106.

From a long-term perspective, the expenses incurred for NEXUS will occur for 20 years, and could extend for 30 years. Those expenses are not insignificant, as evident by the fact that under DTE’s policy the Precedent Agreement and amendment were signed by the Company’s Chairman and CEO because of “the notional value of the agreement.” 3 Tr 421. At this point, the exact nature of the agreement is not finalized, but instead contained in a Precedent Agreement that has an extensive listing of conditions precedent, including the project’s ultimate approval by the Federal Energy Regulatory Commission. Exhibit MEC-10, pgs. 9-10. At some point, the terms and conditions of DTE’s commitment to NEXUS will be definitively established in a contract, and DTE’s long-term natural gas requirements will become clearer.²⁶ Given this, Staff’s contention that the NEXUS contract

²⁶ In testimony filed in November 2015, Mr. Paul indicated DTE expected to file a Certificate of Necessity for the first of the planned CCGT in 2017. 3 Tr 408.

should be provided to the Commission for its review is well-taken, and comports with the holding that a PSCR case should not result in “protracted litigation of policy and technical matters that would delay the PSCR proceeding and would be better handled in a...” more appropriate proceeding. *In re Detroit Edison*, Case No. U-17319, March 6, 2014 Order, pg. 12.

Turning to the merits, none of adjustments and/or reductions to DTE’s PSCR Plan raised by the Attorney General and the GLREA can be sustained on this record. Therefore, seven (7) Finding of Fact DTE advances concerning its 2016 PSCR Plan should be adopted, and the Plan should be approved in its entirety. The issues raised by ANR, MEC/SC, and the Attorney General concerning the cost items relating to NEXUS in the 5-year forecast cannot be sustained, and a Section 7 warning concerning those cost items should not be issued. DTE’s request that its commitment to NEXUS, currently set in a Precedent Agreement executed on July 31, 2014, and amended on September 9, 2015, be approved in this proceeding should be rejected. Accordingly, it is recommended the Commission:

1. Hold the procurement of capacity resources not associated with any power for periods in excess of six months set forth in Plan are reasonable and should be approved under MCL 460.6j(13).
2. Adopt the seven (7) findings of fact concerning the 2016 PSCR Plan proposed by DTE.
3. Determine DTE’s 2016 PSCR Plan, as set forth in the September 30, 2014 Application, establishes the costs it will incur, and steps taken to minimize those costs, rendering the costs reasonable and prudent under the applicable provisions of Act 304.

4. Approve the Plan and authorize a levelized maximum PSCR Factor of (0.20) mills per kWh for the period of January 1, 2016 through December 31, 2016.
5. Hold that the review of a 5-year forecast under MCL 460.6j(7) consists of considering cost items under a reasonable and prudent standard, and if warranted issuing a warning that recovery of the expense in a future proceeding is unlikely.
6. Hold that a cost item in a 5-year forecast cannot be approved under MCL 460.6j(7).
7. Determine that the decisions concerning natural gas transportation made between November 2013 and the July 31, 2014 Precedent Agreement with NEXUS, and the Agreement itself, were reasonable and prudent at the time they were made.
8. Determine DTE's 5-Year Forecast does not contain any cost items for which recovery in future proceedings is, based on this record, unlikely. MCL 460.6(j)(7).
9. Direct DTE to submit to the Commission for its review the contract it ultimately enters into with NEXUS for natural gas transportation services.

MICHIGAN ADMINISTRATIVE HEARING
SYSTEM
For the Michigan Public Service Commission

Dennis W. Mack
Administrative Law Judge

October 28, 2016
Lansing, Michigan